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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006

(NOT CONSOLIDATED)

In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005
And Related Matters.	Application 15-07-007 Application 15-07-008

ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES

Summary

This *Amended Ruling* seeks comments on the Energy Division *White Paper on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral*

Values (White Paper).[1] The objective of the Energy Division *White Paper*, and the issue to be resolved in the Rulemaking (R.) 14-08-013 Distribution Resource Planning (DRP) Proceeding is to determine how to estimate the value that results from using Distributed Energy Resources (DER) to defer transmission and distribution (T&D) infrastructure. An important subsidiary issue is identifying the appropriate level of locational granularity for calculating those values, which may be applied as a single value across each utility service territory, or it may vary by location.

This *Amended Ruling* and *White Paper* are being served jointly to the DRP R.14-08-013 as well as the Integrated Distributed Energy Resource (IDER) R.14-10-003 proceeding service list. The purpose is to make parties to both proceedings aware that the methodology for avoided T&D avoided costs will be decided in the DRP proceeding and (if approved) will be applied into the Avoided Cost Calculator (ACC) as a major update and not be determined separately in the IDER proceeding. This serves to clarify that there will not be two decision-making pathways on avoided T&D for the ACC. Parties to the IDER proceeding who are also parties to the DRP proceeding who wish to comment on the record for this *White Paper* should become parties to the DRP proceeding.

Energy Division will hold a workshop to discuss this proposal on July 8, 2019. Parties are directed to file comments on the amended proposal and respond to specific questions contained in this *Amended Ruling*. Opening

[1] This *Amended Ruling* is different from the June 5, 2019 *Ruling* in two respects: (1) it includes Attachment B which is referenced in the *White Paper* but was inadvertently omitted; and (2) it clarifies the expectations regarding what should be covered by Opening Comments due on June 21, 2019, and Reply Comments due 21 days following the workshop.

Comments, in which the parties should raise the issues that they would like to discuss at the workshop, shall be filed and served no later than June 21, 2019. The Energy Division shall plan the workshop agenda in part to address the issues raised in Opening Comments as well as those identified in the *White Paper*. Reply Comments, in which the parties should address the discussion from the workshop, shall be filed and served no later than 21 days following the workshop.

1. Background

In Decision (D.)17-09-026, the Commission adopted the Locational Net Benefits Analysis (LNBA) to calculate a location specific avoided cost of DERs in accordance with Public Utilities (Pub. Util.) Code § 769. However, D.17-09-026 found that the LNBA methodology was not appropriate for calculating the avoided costs of T&D for DERs procured through Commission mandated programs, such as the energy efficiency (EE) portfolio or net energy metering (NEM). On December 20, 2018, Energy Division staff held a workshop to discuss party proposals for avoided T&D, and presented a proposed approach developed by Energy Division staff. The attached *White Paper* provides additional clarification of the issues for resolution, the staff proposal, and recommendations for location granularity of different use cases. The presentations from the December 20, 2018 workshop have also been attached for reference.

The staff proposal is not intended to be a fully developed and executed methodology, but rather serves as a starting point for consideration of whether avoided cost calculator methodology should be updated to calculate avoided T&D costs based on the forecast data provided in the Grid Needs Assessment (GNA) and Distribution Deferral Opportunities Report (DDOR).

2. Questions for Parties

Please indicate whether you agree or disagree with staff's assessment and recommendations as presented in this paper. If you disagree with any aspect of staff's proposal and recommendations, please provide a detailed rebuttal argument and propose an alternative. An alternate methodology for calculating avoided T&D must be detailed, specific, and actionable.

1. Do you agree with staff's interpretation of the task at hand?
2. Please comment on staff's proposed revisions to the definitions of important terms and proposed framework for specifying use cases.
3. Please comment on staff's assessment of the uncertainty for each category of value and use case, and their recommendations for the appropriate location granularity for the various use cases.
4. Considering staff's preliminary analysis of Pacific Gas and Electric Company's (PG&E's) 2018 GNA, please comment on staff's recommendations regarding the methodology for estimating:
    a. Specified distribution deferral value
    b. Unspecified distribution deferral value
    c. Specified transmission deferral value
    d. Unspecified transmission deferral value

IT IS RULED that:

1. Opening Comments shall be filed and served no later than June 21, 2019.

2. Replies shall be filed and served no later than 21 days following the workshop.

Attachment A: White Paper

Attachment B: Workshop on Improving the Transmission and Distribution Values in the Avoided Cost Calculator December 20, 2018

Dated June 13, 2019, at San Francisco, California.

/s/ ROBERT M. MASON III

Robert M. Mason III
Administrative Law Judge

ATTACHMENT A

ATTACHMENT A

White Paper

ALJ/RIM/gp2 6/5/2019

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES

Summary

This *Ruling* seeks comments on the Energy Division *White Paper on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values*

(White Paper). The objective of the Energy Division *White Paper*, and the issue to be resolved in the Rulemaking (R.) 14-08-013 Distribution Resource Planning (DRP) Proceeding is to determine how to estimate the value that results from using Distributed Energy Resources (DER) to defer transmission and distribution (T&D) infrastructure. An important subsidiary issue is identifying the appropriate level of locational granularity for calculating those values, which may be applied as a single value across each utility service territory, or it may vary by location.

This *Ruling* and *White Paper* are being served jointly to the DRP R.14-08-013 as well as the Integrated Distributed Energy Resource (IDER) R.14-10-003 proceeding service list. The purpose is to make parties to both proceedings aware that the methodology for avoided T&D avoided costs will be decided in the DRP proceeding and (if approved) will be applied into the Avoided Cost Calculator (ACC) as a major update and not be determined separately in the IDER proceeding. This serves to clarify that there will not be two decision-making pathways on avoided T&D for the ACC. Parties to the IDER proceeding who are also parties to the DRP proceeding who wish to comment on the record for this *White Paper* should become parties to the DRP proceeding.

Energy Division will hold a workshop to discuss this proposal on July 8, 2019. Parties are directed to file comments on the amended proposal and respond to specific questions contained in this *Ruling*. Opening Comments shall be filed and served no later than June 21, 2019. The Energy Division shall plan the workshop agenda in part to address the issues raised in Opening Comments as well as those identified in the *White Paper*. Replies shall be filed and served no later than 21 days following the workshop.

1. Background

In Decision (D.)17-09-026, the Commission adopted the Locational Net Benefits Analysis (LNBA) to calculate a location specific avoided cost of DERs in accordance with Public Utilities (Pub. Util.) Code § 769. However, D.17-09-026 found that the LNBA methodology was not appropriate for calculating the avoided costs of T&D for DERs procured through Commission mandated programs, such as the energy efficiency (EE) portfolio or net energy metering (NEM). On December 20, 2018, Energy Division staff held a workshop to discuss party proposals for avoided T&D, and presented a proposed approach developed by Energy Division staff. The attached *White Paper* provides additional clarification of the issues for resolution, the staff proposal, and recommendations for location granularity of different use cases. The presentations from the December 20, 2018 workshop have also been attached for reference.

The staff proposal is not intended to be a fully developed and executed methodology, but rather serves as a starting point for consideration of whether avoided cost calculator methodology should be updated to calculate avoided T&D costs based on the forecast data provided in the Grid Needs Assessment (GNA) and Distribution Deferral Opportunities Report (DDOR).

2. Questions for Parties

Please indicate whether you agree or disagree with staff's assessment and recommendations as presented in this paper. If you disagree with any aspect of staff's proposal and recommendations, please provide a detailed rebuttal argument and propose an alternative. An alternate methodology for calculating avoided T&D must be detailed, specific, and actionable.

1. Do you agree with staff's interpretation of the task at hand?
2. Please comment on staff's proposed revisions to the definitions of important terms and proposed framework for specifying use cases.
3. Please comment on staff's assessment of the uncertainty for each category of value and use case, and their recommendations for the appropriate location granularity for the various use cases.
4. Considering staff's preliminary analysis of Pacific Gas and Electric Company's (PG&E's) 2018 GNA, please comment on staff's recommendations regarding the methodology for estimating:
   a. Specified distribution deferral value
   b. Unspecified distribution deferral value
   c. Specified transmission deferral value
   d. Unspecified transmission deferral value

IT IS RULED that:

1. Opening Comments shall be filed and served no later than June 21, 2019.
2. Replies shall be filed and served no later than 21 days following the workshop.

Dated June 5, 2019, at San Francisco, California.

/s/ ROBERT M. MASON III
Robert M. Mason III
Administrative Law Judge

Energy Division Staff Proposal on Avoided Cost and Locational Granularity of Transmission and Distribution Deferral Values

Executive Summary

The objective of this white paper, and the issue to be resolved in the R.14-08-013 Distribution Resource Planning (DRP) Proceeding is to determine how to estimate the value that results from using Distributed Energy Resources (DER) to defer transmission and distribution (T&D) infrastructure. An important subsidiary issue is identifying the appropriate level of locational granularity for calculating those values, which may be applied as a single value across each utility service territory, or it may vary by location.

PU Code Sec. 769 (AB 327, 2013) directed IOUs to file with the Commission distribution resources plans (DRPs) that among other things evaluate locational benefits and costs of distributed energy resources (DERs). "This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation."[1]

Currently, the Avoided Cost Calculator (ACC) is used to inform the cost-effectiveness of Commission demand-side programs and tariffs, such as NEM, including the avoided costs of T&D. Today the ACC has a single avoided distribution value in each of the SCE and SDG&E territories based on the marginal cost of distribution from the GRC. The PG&E avoided cost of distribution value is also based on the marginal cost of distribution from the GRC and is further broken out by climate zone. The ACC has a single avoided transmission value in the PG&E territory and a zero value in SCE and SDG&E territory.

The Commission adopted the Locational Net Benefits Analysis (LNBA) methodology in the Track 1 Decision of the DRP proceeding (R.17-09-026) in 2017 in order to calculate a locationally specific avoided cost of DERs. The Track 1 Decision found the LNBA methodology developed by the LNBA working group to be useful for calculating the avoided costs for specific distribution deferral projects that the IOUs were considering for competitive solicitation. The decision did not find the LNBA methodology was appropriate for calculating the avoided costs of T&D for DERs procured through Commission mandated programs, such as the EE portfolio or NEM. Thus, the Commission in D.17-09-026 ordered further action to address it, in the context of further developing a "cost-effectiveness use case" for the LNBA methodology. Parties submitted proposals on methods of calculating unspecified T&D deferral value on December 5, 2017. A Ruling posing specific questions on parties' proposals was issued on March 29, 2018. Parties provided comments on the proposals on April 30, 2018. Staff subsequently held a workshop on December 20, 2018. The workshop agenda and presentation materials are included as Appendix B.

To help the Commission move further towards resolving this issue, this Staff Proposal offers:

1) a set of updated definitions of important terms and concepts;
2) a refinement of the definition of "use cases" previously described in D.17-09-026;

[1] PU Code 769 (b) (1)

3) a proposed approach for estimating unspecified distribution and transmission deferral value;
4) an overall set of recommendations; and
5) a set of questions intended to complete the record needed to enable the Commission to adopt a policy on this issue via Decision.

The underlying concepts at issue in the DRP Proceeding are inherently abstract and complex. As a result, it is easy for deviations to arise in how different terms are used by different individuals or parties. This, in turn, can lead to misunderstandings and frustrate progress in developing solutions. Therefore, staff found it was necessary to more clearly define these concepts and recommendations prior to seeking input from parties, to ensure that parties have the same understanding of the proposals under consideration. Furthermore, this white paper proposes a concrete methodological approach to calculating distribution deferral, provides a preliminary analysis applying the methodology, and provides recommendations for how the methods should be applied to different types of use cases. However, staff's recommendations are intended to serve as a starting point for a discussion with parties, rather than a complete and fully developed methodology.

Additionally, the paper does not intend to significantly alter current CPUC and CAISO methodologies of calculating the specified distribution and transmission deferral value. The paper does comment on how these related concepts fit into the overall framework of distribution and transmission deferral value.

1. Updated Working Definitions

Due to the complexity and challenges described above, terms and concepts promulgated in prior working group, staff, and/or Commission forums may merit revision in light of information and experience gained through subsequent activity. To that end, staff proposes below an updated set of working definitions of certain DRP terms and concepts. These definitions apply throughout the rest of this document (unless otherwise noted) and are proposed for general future use in the DRP Proceeding.

Rather than being listed individually, many of the definitions below are provided as pairs of contrasting, but sometimes confused concepts.

Non-targeted DER growth: The CEC develops a forecast of DER growth in the Integrated Energy Policy Report (IEPR), which the IOUs disaggregate to establish the circuit level forecast for distribution planning. The IEPR forecast includes two types of DER growth:

- Non-targeted DER growth refers to an increase in DERs over time that results from Commission-ordered policies, programs, or tariffs that are not locationally targeted to defer transmission and distribution upgrades.[2]
- "Naturally occurring" DER growth is also included in the demand forecast, which results from customer adoption of DERs that are not supported by any tariff or incentive payments. This

[2] The concept of "autonomous DER growth" was referenced in D.17-09-026 on pg. 46 to explain the avoided cost use case for the LNBA. Since this term has alternate definitions in other proceedings, we will cease to use the term in this proceeding and will instead refer to the term "non-targeted DER growth."

category includes DER growth resulting from codes and standards[3], the development of which are sometimes supported by ratepayer funding, and which may vary by climate zone within the state.

Targeted DER Procurement: This refers to DER procured in response to a specific identified need at a specific location. The DRP Distribution Investment Deferral Framework (DIDF) is one example of targeted DER procurement, but there may be other examples as well.

Avoided costs vs. cost effectiveness: Avoided costs are costs of providing electricity (e.g., building power plants, buying natural gas) that would have been incurred if not for some action taken, such as the installation of an energy efficiency measure or unit of DER equipment. They represent a source of value, or benefit, associated with that action. Cost effectiveness, on the other hand, refers to the relationship between the benefits and the costs of the action. Avoided costs are the inputs used to estimate the benefits in the cost effectiveness calculation.

Note: These concepts are sometimes confused in discussions of LNBA. LNBA is an approach to adding up several different avoided costs, or benefits, of DERs in a particular location. LNBA addresses avoided costs but does not address cost effectiveness. The confusion arises because a given avoided cost of a DER in a particular location could be negative. That means that instead of a benefit, the avoided cost would actually be an incurred cost. The "net" part of LNBA reflects the fact that multiple streams of avoided costs are added together, one or more of which may be negative, resulting in a net value. The fact that LNBA can involve adding up both positive and negative values can make it seem similar to a cost effectiveness calculation. However, LNBA explicitly and deliberately does not consider the costs of the DER itself, which is a foundational component of a cost-effectiveness calculation.

Avoided T&D: This phrase refers to avoided or deferred transmission and distribution infrastructure. It is sometimes used as a shorthand for transmission and distribution deferral value. See also "deferral vs. avoidance."

DERAC vs. ACC: These two names refer to the same underlying tool. Avoided Cost Calculator (ACC) is the name used in the Integrated Distributed Energy Resources (IDER) and DER resource proceedings, whereas Distributed Energy Resource Avoided Cost (DERAC) is the name that became common in the DRP proceeding. Going forward DRP will use the ACC terminology to avoid confusion. The CPUC's ACC reflects the avoided costs of electricity and are modeled based on the following components: generation energy, generation capacity, ancillary services, transmission and distribution capacity, environment (i.e., avoided greenhouse gases), and avoided renewable portfolio standard. The avoided cost model is annually updated to improve the accuracy of how benefits of demand-side resources are calculated. The most recent update was completed in 2018. For more information go to the CPUC's Cost Effectiveness webpage.

Counterfactual forecast vs. unmanaged forecast: Both terms refer to a load forecast from which forecasts of the adoption of load-modifying distributed energy resources, such as energy efficiency, demand response, battery storage, rooftop photovoltaic (PV), and electric vehicles, have been removed,

[3] Codes and Standards (C&S) are categorized as both naturally occurring and Commission-ordered policies. The C&S program administered by the IOUs contributes substantial analysis to the adoption of Title 24 Code as well as federal appliance standards, for which the IOUs receive credit toward their savings, based on individual analysis of IOUs' contribution to the adoption of each standard.

for the most part. The term “unmanaged forecast” is more frequently used in the context of the California Energy Commission’s (CEC) Integrated Energy Policy Report (IEPR) process as synonymous with their “base forecast,” whereas the term “counterfactual forecast” has been used in the DRP proceeding.[4]

There is a small difference in the two concepts. The counterfactual forecast in DRP reflects the removal of only those DER load impacts that are the result of Commission policies, including tariffs like Net Energy Metering (NEM).[5] In contrast, the unmanaged forecast reflects the removal of all incremental DERs, regardless of whether the load impacts result from Commission policies or other policy initiatives, such as CEC or federal efficiency standards that would have happened regardless of Commission-approved funding.

A counterfactual forecast is also different from another type of counterfactual analysis with which it is sometimes confused. For the purposes of evaluating the influence of different actions (such as programs or measures) that have already taken place, an important question is: what would have happened if not for that action? This kind of question is outside the scope of the DRP proceeding entirely. The DRP proceeding is concerned only with the counterfactual future, not the counterfactual past. The relevant question that drives interest in the idea of a counterfactual forecast in the DRP proceeding is: what would happen to load in the future in the absence of any Commission-driven DER procurement policies (including tariffs)?

Deferral vs. avoidance (“deferral value”): DERs may be used to defer upgrading a piece of equipment by reducing the growth of load that would otherwise be expected to drive the need for an upgrade. If the DER allows a permanent deferral of an upgrade, then that equipment is _*avoided*_. Note that existing equipment will eventually need to be replaced, so what the DER is avoiding is specifically the upgrade that would otherwise occur. Avoidance is a special deferral case where the length of the upgrade deferral is equal to or greater than the expected useful life of the underlying equipment.

Note: A related but conceptually separate value is the difference between the cost of the equipment that must eventually be installed and the cost of the equipment that would otherwise need to be installed if not for the DERs. The phrase “deferral value” is used as an umbrella term to refer to the sum of these two types of value.

Planning vs. Procurement: Planning and procurement are distinguished by whether compensation is centrally involved. Procurement refers to activities that involve compensation intended to add or make an electrical resource available to the grid (including on the customer side of meter), including tariffs, solicitations, or incentive programs. Planning refers to activities that involve the establishment of high level goals or targets that do not directly result in compensation from ratepayers to resource providers. Examples include: energy efficiency or demand response potential and goals studies, Reference System Plan portfolio optimization in Integrated Resource Planning (IRP).

Note: Planning and procurement activities may not always indicate that the same set of resources represents the least cost or greatest value solution for meeting an identified need. Deviations between

[4] A nuance is that the CEC base forecast includes a small amount of so-called “committed” energy efficiency.
[5] Practically speaking, a DRP counterfactual forecast might also exclude certain types of Commission policies that are implemented for reasons less directly dependent on cost-effectiveness.

the resources indicated by a planning analysis and those actually procured can arise when different approaches to valuing resources are used in each process. Even when the underlying methodologies are identical, however, procurement outcomes may still deviate from the outcomes projected in planning exercises due to differences between forecasted resource costs (or other assumptions) and actual prices offered in the context of a proposed market transaction.

Specified deferral value: Value associated with deferring the purchase and installation of specific infrastructure that has been identified by a utility or California Independent System Operator (CAISO) as needed for grid reliability, resiliency or safety. Deferral value is generally associated with capacity-related projects whose need can be affected by changes in peak demand.

Value associated with deferring specific infrastructure identified as needed for other purposes (i.e. GHG reduction, renewable portfolio standard (RPS) compliance, or economic benefits) is a conceptually separate type of value and is excluded from this definition but not from consideration in cost-effectiveness calculations. What this means is that a Request for Offer (RFO) for DERs purchased to defer a planned distribution investment should evaluate the bids by determining their deferral value plus any and all values recognized by the Commission.

Unspecified deferral value: Value associated with deferring the purchase and installation of generic infrastructure that has not been specifically identified by a utility or by the CAISO as needed for grid reliability, resiliency, or safety, but is estimated to be needed. This value reflects the concept that not all grid needs can be anticipated with perfect foresight, and some portion of those unanticipated grid needs could be satisfied by DERs.

Relationship of specified and unspecified deferral value: Specified deferral value has been most commonly associated with the Distribution Investment Deferral Framework (DIDF), and unspecified deferral value has been most commonly associated with providing inputs to the ACC which is then used to inform the evaluation of the cost effectiveness of various Commission-supported demand-side programs such as NEM. There is nothing theoretically preventing the combination of these two separate sources of value. The more obvious example is DIDF. While the primary source of value in a DIDF procurement is the specified deferral value stated in the RFO, the valuation of DER bids must also include any unspecified deferral value as defined by Commission policy. Non-targeted DERs will have some unspecified deferral value but depending on their location may also have some specified deferral value.

Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR): In D.18-02-004, the Commission required the IOU to submit an annual GNA filing each year wherein the IOUs provide a comprehensive list of distribution facilities and forecasted grid needs which inform the Distribution Deferral Investment Report (DDOR). The DDOR presents a list of candidate distribution deferral opportunities that result from an initial deferral screening process. Pursuant to a recent ALJ Ruling the GNA and DDOR are filed together on August 15 each year and now include transmission grid needs that are subject to CPUC jurisdiction.[6]

[6] *Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process,* May 7, 2019.

Locational Net Benefit Analysis (LNBA) v. Avoided T&D inputs for the ACC: The concept of the LNBA was defined to meet the requirements of PU Code 769 b(1), which requires the IOUs to submit a proposal to "Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation." D.17-09-026 adopted an LNBA methodology that could be applied to two of the three use cases identified in the decision as further discussed in the next section. The decision did not approve the use of LNBA for the purpose of calculating values for the avoided cost calculator. To avoid future confusion, "LNBA" will be used to refer to the methodology developed and adopted in D.17-09-026 and this paper will propose the method to develop avoided T&D cost inputs for the ACC.

2. Clarifying the Framework for Specifying Use Cases

Ordering Paragraph (OP) 14 of D.17-09-026 articulates three use cases for LNBA:

> "The Locational Net Benefit Analysis use cases for: 1) Public Tool and Heat Map; 2) prioritization of candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework; and 3) providing location-specific avoided transmission and distribution inputs into the Integrated Distributed Energy Resources Distributed Energy Resources Avoided Cost Calculator for cost-effectiveness evaluation, informing Distributed Energy Resources incentive levels, and other applications, are adopted."

Elsewhere in the Decision, the use cases are described in similar, though not identical ways (see p. 42, COL 5, and OP 15). In these various instances throughout the Decision, the description of the LNBA use cases sometimes inadvertently implies a conflation of four different categories that would be useful to explicitly distinguish from each other: values, methodologies, tools, and use cases. Proposed definitions of these categories, as they apply within DRP, are as follows:

- **A value** is a benefit, usually in the form of an avoided cost, that DERs provide when they are constructed and used.
- **A method, or methodology** is a set of mathematical or conceptual relationships that prescribe how to develop a set of output information from a set of input information.
- **A tool or model** is software in which a specific methodology is implemented.
- **A use case** is a human activity in which a tool, a methodology, and a value may be used.[7]

[7] Under a more nuanced framework an activity might be more precisely called an "ultimate" use case. A "proximate" use case could be a methodology, tool, or activity – whatever the value, methodology, or tool is immediately used in. A "complete" use case would be the full set of proximate use cases leading up to the ultimate use case. The one presented above is deliberately simpler.

A simple way to articulate the relationship between these categories is as follows: A value is represented as a number within a tool that implements a methodology in order to develop information for an activity. The use case for the value, methodology, or tool is the activity that it informs.[8]

Examples of each category are presented in the tables below.

Table 1. Examples of Values

1	Specified Distribution Deferral Value
2	Unspecified Distribution Deferral Value
3	Specified Transmission Deferral Value
4	Unspecified Transmission Deferral Value

Table 2. Examples of Methodologies

1	LNBA
2	Integrated Capacity Analysis (ICA)

Table 3. Examples of Tools or Models

1	Avoided Cost Calculator (ACC)
2	LNBA Tool
3	ICA online map
4	A production cost simulation model
5	A capacity expansion model
6	Proprietary procurement valuation tools
7	A power flow model

[8] Note that a value may be an input or output of a methodology. For example, using these definitions, it is logical to refer to a methodology for developing an avoided cost, as well as to a methodology that uses an avoided cost as input to calculate cost-effectiveness.

Table 4. Examples of Use Cases

	Planning
1	DER developer business development[9] (i.e. Public Tool and Heat Map)
2	DIDF prioritization of candidate deferrals[10]
3	Integrated Resource Planning (IRP)
4	Energy efficiency (EE) potential and goals studies
5	Demand response (DR) potential study
	Procurement[11]
	Tenders/Solicitations
1	DIDF Competitive Solicitation Framework RFOs
2	Transmission Planning Process (TPP) RFOs
3	Energy storage RFOs
4	NEM tariffs
5	IDER DER sourcing tariff (if adopted)
	DER Program Budget
6	EE portfolio budget setting
7	DR program and budget proposals

As shown in Table 4, use cases fall into two groups: planning and procurement. As described in the updated definitions above, planning and procurement are distinguished by whether compensation is centrally involved. In addition, Table 5 presents the possible levels of locational granularity of the T&D deferral, which must be determined for the different use cases.

Table 5. Examples of Possible Levels of Granularity

specific unit of equipment
node (pole, line segment)
circuit/feeder
Substation/feeder bank
distribution planning area
transmission zone
transmission access charge territory
utility territory

[9] Identified in D.17-09-026 as the first use case, Public Tool and Heat Map
[10] Identified as the second use case in D.17-09-026
[11] The third use case identified in D.17-09-026 is expected to provide the inputs for the avoided cost calculator, which informs the non-RFO forms of DER procurement, including NEM tariffs, EE and DR portfolio budgets.

Purpose of Clarifying Use Cases

One of the challenges in addressing the issue of developing locational transmission and distribution deferral values has been in interpreting the three uses cases ordered by D.17-09-026. Using the four categories described above to interpret OP 14 helps to clarify the task at hand and to reveal some of the difficulties in completing it.

Ordering Paragraph 14 identified the use cases for what we have now defined as a methodology ("Locational Net Benefit Analysis"). Recall that use cases for values, methodologies, and tools are activities. However, the description of the first use case uses dicta that specify a tool, rather than an activity. The second use case identified in the LNBA Decision indicates that the activity that should be understood as the use case in this instance is "to identify potential optimal locations for deploying DER based on candidate deferral opportunities identified in the distribution planning process, along with detailed information about the required DER attributes necessary to achieve such deferrals."[12] This could be considered a planning type of use case, since it revolves around identifying locations for project development, rather than compensating projects, but the LNBA working group also intended for this use case to enable compensation to DER developers for building DERs in locations that would defer distribution upgrades, although it did not explicitly consider what the procurement mechanism should be.[13]

The description of the second use case in OP 14, unlike the first use case, does explicitly describe a specific activity, consistent with the new categories: "prioritization of candidate distribution deferral opportunities as part of the Distribution Investment Deferral Framework." Although DIDF includes a solicitation process, this part of the process only involves identifying possible parameters for targeting procurement and does not drive procurement itself. As a result, the prioritization use case is considered planning, whereas the RFO process itself is considering procurement. These categorizations of different phases of the DIDF process are reflected in the table above.

The description of the third use case marks a shift from the paragraph's overall focus on the use cases for the LNBA methodology to something else. Instead of identifying an activity for which the LNBA should be used, it suggests that LNBA should itself be modified to include specific values, namely "location-specific avoided transmission and distribution inputs," that could then also be added to a specific tool ("…Avoided Cost Calculator"). That latter tool would then be used in three different use cases that are at least somewhat recognizable as activities according to our new definition:

1. Cost effectiveness evaluation
2. Goals and budget setting
3. Potentially informing [DER] incentive levels, if Commission decides to implement a new tariff structure[14]

Interpreting this part of the paragraph using the updated definitions presented in this paper suggests the following actions:

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[12] Pg. 42 of D.17-09-026
[13] Pg. 26 of Locational Net Benefit Analysis Working Group Final Report
[14] This potential application would be considered in the IDER proceeding, R. 14-10-003

Action 1: Identify appropriate methodologies to produce two new deferral values (transmission and distribution deferral values).

Action 2: Develop a modeling tool to produce updated locational net benefit values across the electrical system that reflect the new deferral values.

Action 3: Implement actions 1-2 in a way that allows the locational net benefit values to be incorporated into the ACC methodology and tool, as well as other potential methodologies and tools.

Action 4: Implement actions 1-3 in a way that enables the ACC and other methodologies and tools that use the underlying deferral values, to be deployed in a wide range of use cases, including both planning and procurement.

The first two use cases described above do require additional refinement, and proposals for refinement were reported in The LNBA Working Group Long Term Refinements Final Report. The focus of this paper, however, is to address issues associated with third use case: providing location-specific avoided transmission and distribution inputs into the Integrated Distributed Energy Resources Avoided Cost Calculator for cost-effectiveness evaluation, informing Distributed Energy Resources incentive levels, and other applications.

3. Challenges to Developing an Avoided T&D Methodology

The application of the updated definitions and new use case framework gives us a more precise, explicit, and complete description of the task before us. It also helps us to understand more clearly some of the challenges in completing the task.

For example, the wide range of use cases contemplated in action 5 above, which span both planning and procurement use cases, can make it seem difficult to determine the appropriate methodology to be developed in action 1. For example, it is conceivable that methodologies appropriate for planning activities may not establish an acceptable basis for allowing cost recovery for procurement activities.

The nature of the deferral value to be calculated in action 1 creates another challenge. Although the distinction was not explicitly made in prior rulings or decisions, SCE's proposal for estimating locational transmission and distribution deferral value helpfully introduced the terms "specified" and "unspecified" to refer to the two types of deferral value.

SCE's proposal characterized the third LNBA use case (under the definition of D.17-09-026) as being related to the unspecified type of deferral value. However, using our new framework for thinking about use cases, it is clear that D.17-09-026 implicates many different use cases for transmission and distribution deferral value. That raises the question of whether the same type of deferral value is appropriate for all of those use cases.

In consideration of these challenges, it may be tempting to try to evaluate all of the proposals submitted by parties for estimating locational transmission and distribution deferral value for each of the use cases listed in Table 4 to determine which proposals may be appropriate for which use cases. To reduce the scope of the challenge, the Commission could also explicitly prioritize one or more specific use cases of interest. For example, the Commission could prioritize the development of avoided T&D values specifically for approving EE program budgets. Another option would be to conclude that no feasible options are available and to leave the T&D deferral values currently used in the ACC unchanged.

Implications of the Uncertainty of Locational Avoided T&D Values

When considering how the avoided T&D values will be applied to the planning and procurement use cases, a closer examination of the uncertainty involved in the two types of deferral helps point toward a simpler solution. Specified deferral value derives from the identification of clearly defined future grid needs and infrastructure investments that a utility is likely to make, subject to additional analysis to reflect the extent to which the need may be met by DERs instead. Each of the processes involved in calculating specified deferral value involves some level of uncertainty. It is possible that the identified future grid need might not actually come to pass even without the proposed investment. It is possible that the infrastructure investments that are identified may not meet the need as well as anticipated. It may be that a piece of equipment may not be as deferrable with DERs as originally envisioned. These are uncertainties inherent to estimates of specified deferral value as well as distribution grid planning. Unspecified deferral value derives from determinations that are likely even more subject to change and error than those underlying specified deferral value. For unspecified deferral value, conditions may suggest the possibility of a future grid need, but there is an even greater chance that the need may never come to pass, the timing of the need may change, the type of infrastructure suitable for meeting the need may change, or that the technical suitability of DERs for deferring that infrastructure may change.

At the same time, it does not seem to be reasonable to conclude that, outside of the DIDF process, no DERs ever contribute to deferring distribution or transmission infrastructure in any location. The problem is that it is difficult to predict which of the potential future needs across the grid will eventually materialize as concrete, specified, deferrable projects. In other words, unspecified deferral value very likely exists to some degree, but the location of that value is extremely uncertain.

4. Energy Division Proposal to Calculate Unspecified Transmission and Distribution Deferral Value

At the December 20, 2018 workshop, Energy Division staff presented a straw proposal to calculate the unspecified distribution deferral value based on Grid Needs Assessment (GNA) data. This proposal is intended to serve as a starting point for discussing the approaches used to quantify the avoided costs of transmission and distribution rather than a fully developed methodology. The proposal for calculating distribution deferral involves simplifying assumptions and that need to be addressed in order to develop a complete methodology, and once adopted in the DRP proceeding, the method would need to be incorporated into the avoided cost calculator. Energy Division staff is seeking input on whether the GNA serves as the most reasonable starting point for calculating the impact of non-targeted DERs on the deferral of distribution, and whether, in light of this analysis, what locational granularity should be applied within the avoided cost calculator for unspecified deferral.

In addition to ED staff's proposal, PG&E presented a proposal at the workshop that offers a way to incorporate both unspecified and specified distribution deferral value. Under PG&E's proposal, unspecified deferral value is not locationally specific, while their specified deferral value is locationally specific. PG&E's proposal does not provide an analysis of the distribution impacts of the non-targeted DERs embedded in the forecast. This type of approach mirrors that in use in New York, as presented in the December 20 workshop by E3. SCE presented a proposal on calculation of avoided transmission values. These presentations have been attached to the white paper in Appendix B.

Energy Division Proposal to Calculate Unspecified Avoided Distribution Costs Based on GNA Data

Energy Division staff proposes to estimate the total value of distribution deferrals resulting from non-targeted DER growth using existing data from the utilities' General Rate Case (GRC), GNA and the Distribution Deferral Opportunity Report (DDOR). To better explain the proposed methodology, staff has developed a simplified, preliminary analysis using PG&E's 2018 GNA and DDOR data.[15] The results of this analysis are not intended to be applied as actual avoided costs of distribution, but are provided to demonstrate how the GNA and DDOR data may be used to estimate avoided costs of distribution. Staff anticipates the methodology incorporated into the avoided cost calculator would address the shortcomings to this preliminary analysis, which are listed in the following section.

To facilitate explanation of this approach, we have separated the calculation into a price (*P*, the average value of deferring distribution system upgrades, expressed as the average $ per kW of distribution upgrade capacity) and quantity (*Q*, amount of distribution system upgrades deferred by DERs) component. In its simplest form, avoided costs are calculated as *P*Q,* which results in a single, system level distribution deferral value for the non-targeted DERs that are embedded in the demand forecast, in $/kW. Since marginal costs are built up from several components, some resolution is needed on what aspects of an IOU's marginal distribution capacity costs can be applied to this calculation as well as to further clarity on the source of this data. The approach to calculate the quantity (*Q*) is broken down into four sequential parts, described below. Each step is illustrated with a sample calculation of six circuits from the PG&E's load data.

Part 1: Estimate the capacity of distribution system upgrades deferred by DERs *(Q)*

1. **Calculate the Counterfactual Forecast:** The circuit-level counterfactual load (as defined in the updated working definitions) and distribution capacity deficiency can be derived from the data in the GNA by adding the circuit-level DER forecast to the circuit-level load. The circuit-level counterfactual forecast stems from GNA data on the capacity deficiency on each circuit to 2024, based on the latest data (i.e. the 2018 DIDF cycle). Adding back in the forecasted DERs that are 'assigned' to each circuit can produce an estimate of counterfactual load: the load that would have occurred if future non-targeted DERs are removed from the forecast. In this simplified analysis, DERs are being treated as additive to demand. Caveats and limitations to the simplified analysis are discussed in the following section.

[15] The staff's preliminary analysis could not be conducted with SCE and SDG&E's 2018 GNA, because it did not include facility loading or forecasts data for circuits that were not overloaded.

Table 6. Sample Circuit-level Calculation of Counterfactual Forecast

Circuit ID	2022 Demand Forecast (MW)	DER Forecast in 2022 (MW)				2022 Counterfactual Forecast (MW) *(Demand + DERs)*
		EE	DR	PV	Storage	
1	1.76	0.05	0.01	0.12	0.00	1.94
2	0.30	0.01	0.00	0.00	0.00	0.32
3	10.53	0.29	0.01	0.64	0.00	11.47
4	11.69	0.39	0.04	0.86	0.00	12.97
5	10.49	0.31	0.02	0.83	0.00	11.65
6	12.07	0.40	0.03	0.91	0.00	13.41

Source: Sample set of circuits from PG&E's 2018 GNA

2. **Calculate capacity overload for counterfactual forecast:** The capacity overload that is deferred by DERs embedded in the forecast can be estimated from the facility capacity and loading percentage provided in the GNA, by calculating the facility loading percentage as a ratio of counterfactual forecast to the facility capacity. This calculation is consistent with how the loading percentage is derived for the actual planning forecast. All circuits that are above 100% loading are considered overloaded. However, only circuits that are overloaded in counterfactual forecast, and not in the actual planning forecast are counted as deferred by non-targeted DER growth (DER growth that is embedded in the forecast). In the sample calculation below, Circuits 4 and 6 would be overloaded in 2022 if the DER forecast is not realized.

Table 7. Capacity Overload for Sample Circuits in Counterfactual Forecast

Circuit ID	Facility Rating (MW)	2022 Demand Forecast	2022 Facility Loading (%)	2022 Counter-factual Load (MW)	Counter-factual Facility Loading (%)	6. Circuit Overload MW
(source)	*GNA Data*	*GNA Data*	*GNA Data*	*Step 1 result*	*CF load /facility rating*	*CF load – facility rating*
1	7.12	1.76	24.7	1.94	26.76	0.00
2	4.49	0.30	6.7	0.32	7.24	0.00
3	12.34	10.53	85.3	11.47	88.58	0.00
4	11.82	11.69	98.9	12.97	104.93	0.58
5	12.19	10.49	86.1	11.65	91.26	0.00
6	12.19	12.07	99.0	13.41	103.92	0.48

The sum of capacity overloads in PG&E's counterfactual forecast is 91 MW.

3. **Estimate the percentage of distribution capacity overloads that lead to deferred distribution upgrades:** For this preliminary simplified analysis, staff is only calculating a system level quantity for deferred distribution capacity. The challenges in calculating a locationally specific value are addressed in the next section. Staff proposes to base this assumption on the ratio of such capacity overloads identified in the GNA to those capacity overloads that are potentially deferrable as

identified in the DDOR. This resulting percentage is a proxy for distribution capacity upgrades that can be deferred by DERs, which can be applied to the capacity overload of each circuit that was calculated in step 1.

Table 8. Percent of Distribution Capacity Overloads that Require Distribution Upgrades

		Total # of Feeders	Feeder Capacity (MW)	*Source*
a	Total capacity overloads on system	183	2,328	*GNA*
b	Overload addressed by load transfer	144	1,799	*GNA*
c	Planned Investments	39	528	*DDOR*
d	**Ratio of overload capacity to require distribution upgrades**	**21%**	**23%**	*=c/a*

Counterfactual Forecast

e	Capacity overloads in counterfactual forecast	208	91	*sum of circuit overloads in Step 2*
f	**Planned Investments deferred by DERs embedded in forecast**	44	21	*=e*d*

The estimated deferred capacity of the overloaded circuits can be used to arrive at a system-level quantity of distribution capacity that is deferred by DERs embedded in the forecast. (i.e.,*Q).*

Part II: Estimate the value of deferring distribution system upgrades *(P)*

4. **Calculate the marginal cost of the deferred distribution upgrades**. Staff proposes that the marginal cost is based on the total planned investments in the DDOR filing, (DDOR_MC $/kW-yr) DDOR MC is the sum of the total cost of planned investments in the DDOR filing divided by the capacity deficiency that the planned investments are mitigating. This value is expected to be higher than the marginal cost of distribution in the GRC, which divides the cost of distribution by all load growth in the system.[16]

5. **Calculate system-level avoided distribution costs:** For an initial, simplified estimate of the locational avoided distribution capacity cost, we multiply *P* by the amount of deferred distribution capacity for each circuit calculated in the previous step (i.e., *P*Q*). To do so, we add the Q across all the circuits and multiply the result by P (ie. marginal cost of distribution, and then divide by the sum of the 10-year forecasted level of DERs forecasted in all the circuits (as expressed in megawatts (MW) for each circuit). This results in a single, system level distribution deferral value for the non-targeted DERs that are embedded in the demand forecast, in $/kW.

   ED staff will decline to make the calculation in step 4-5, since the result may be misconstrued to represent the actual avoided cost of distribution. A more comprehensive analysis is necessary to

[16] Staff recommends that the DDOR MC is only used if it is higher than the GRC MC value.

address the limitations in this simplified analysis in order to calculate an accurate value, as discussed below.

Limitations of Staff's Preliminary Analysis and Implications for Finalizing an Avoided Distributions Cost Methodology for the Avoided Cost Calculator

This preliminary analysis is not intended to calculate the actual avoided costs results because this analysis is limited by several analytical challenges and methodological limitations that need to be improved and/or addressed to finalize the methodology:

1. **The 2018 GNA was incomplete.** The 2018 GNA data is not comprehensive, since D. 18-02-004 allowed the IOUs to submit their available data and did not require the full GNA to be submitted until 2019. In the 2018 GNA, only PG&E's dataset included the full list of distribution circuits, including those that are not overloaded, which is necessary to run to run a preliminary analysis. Even PG&E's dataset is limited to feeders and does not include all equipment on each feeder. This limitation can be addressed in a future iteration of the analysis, after the 2019 GNA has been submitted that includes a complete set of forecasted grid needs and planned projects, which could potentially increase the total capacity of deferred equipment.
2. **DER production shapes must be applied.** To accurately remove DERs from the forecast, DER production shapes need to be applied to the load shape of the demand forecast, since DERs may be generating or saving at less than their full capacity during the circuit's peak period. PG&E applies the Peak Capacity Allocation Factor (PCAF) to their marginal cost, and a similar calculation would be needed for SCE and SDG&E. Considering that approximately half the DER forecast is PV and a small portion of PV generation occurs during system peak, a significant portion of the DER MW capacity will not reduce the peak load on the feeder.[17] As a result, Energy Division's preliminary results are likely to overestimate the impact of DERs on the circuit level forecast. This limitation would need to be addressed in a future iteration of the analysis by applying load shapes to the counterfactual loading.
3. **Naturally-occurring DERs should remain in the counterfactual forecast.** The DERs in the counterfactual forecast include two types of DER growth from the IEPR forecast: DER growth driven by Commission-mandated incentives and tariffs, and naturally occurring DER growth. To accurately account for the impact of non-targeted DER growth on avoided T&D, only DER growth driven by Commission-mandated incentives and tariffs should be removed from the IEPR forecast, because the purpose of the avoided cost calculator is specifically assessing the value of these incentives and tariffs. Making this adjustment would require a breakout of DERs by driver in the GNA and would result in reducing the impact of DERs on distribution deferral.
4. **GNA's five-year forecast horizon should be extended.** The impact of DERs to defer distribution upgrades accrue over the long term, while the GNA is limited to the forecast horizon that is necessary for distribution planning. For actual distribution planning, investments are only planned on a five-year forecast horizon. For estimates in the avoided cost calculator, the horizon should be extended to estimate DER deferral value for the cumulative impact of DERs over their expected useful life. Roughly speaking, the number of identified projects should be multiplied by 4 to reflect

[17] Peak demand has shifted to evening hours due increasing penetrations of solar generation. As a result, PV generation has ceased to reduce peak system demand.

long-run 20 years of DER impact. This would likely result in increasing the impact of DERs on distribution deferral.

5. **It is uncertain which circuits require distribution upgrades vs. no-cost load transfers.** A substantial portion of the distribution capacity overloads are addressed through no-cost reconfiguration of the distribution circuits. The determination of which circuits require distribution upgrades and which circuits are addressed through load transfers requires iterative power flow analysis and the judgment of qualified distribution engineers and planners. It appears to be exceedingly difficult to predict with a high degree of confidence which specific circuits that appear to be overloaded in a counterfactual analysis would require distribution upgrades.
6. **Preliminary analysis is based on the current load forecast trajectory, with low load growth.** Even with DERs removed from the forecast, the trajectory of load growth is relatively low for the next five years. Deferred distribution upgrades may increase in the future if building and transportation electrification drive future load growth. High electrification scenarios could potentially be applied as a sensitivity case to the proposed methodology to evaluate the possible impacts of building and transportation electrification growth on distribution deferral.

Thus, to develop a locationally specific estimate of the distribution deferral of DERs, an estimate of distribution capacity would need to be derived based on assumptions regarding which circuits would have required distribution upgrades in the absence of DER growth. Step 3 of staff's analysis only calculates a system level avoided cost of distribution. In order to determine the distribution avoided cost on a locational basis in the avoided cost calculator, the methodology will need overcome the lack of predictability of which specific grid needs can be addressed with load transfers and which require new, and potentially deferrable, infrastructure. This informs staff's current recommendation discussed later in the paper to keep the unspecified avoided distribution value uniform across each IOU territory.

All of the other above limitations will also need to be addressed to improve the methodology.

Findings from Energy Division's Preliminary Analysis of Distribution Deferrals in PG&E Territory

Considering these limitations, Energy Division completed its initial calculation using PG&E's 2018 GNA data in order to understand the potential *scale* of deferred distribution capacity embedded in the forecast. Based on PG&E's 2018 GNA, 1,700 MW of DERs are forecasted to be installed and an estimated 90 MW of additional capacity overloads is avoided due to the non-targeted DER deployment by 2022. In the context of the overall distribution system capacity, this impact is small: PG&E's forecasted demand in 2022 is 23,000 MW; PG&E's overall distribution system capacity is 33,000 MW.

Out of the 3,300 feeders in PG&E's territory, 203 of them would have been overloaded, but are not now, due to the DERs embedded in the forecast. These 203 feeders represent the list of potential distribution upgrades that were deferred by non-targeted DERs. However, 185 of those feeders are only overloaded by less than a MW, so presumably, many of these grid needs would have been addressed through load transfers and therefore would not have presented a deferral opportunity. Furthermore, only two feeders on the system had deficiencies that were greater than 2 MW that was reduced to the extent that there was no capacity overload in the actual forecast.

The scale of these impacts is in line with the scale of the distribution overloads and planned distribution upgrades that are identified in the PG&E 2018 DDOR:

Table 9. Overview of Results from PG&E Preliminary Analysis

	Distribution Facility Rating (MW)	Overloads and planned upgrades in GNA: Specified Deferrals		Overloads by non-targeted DERs embedded in counterfactual forecast:* Unspecified Deferrals	
		# of Feeders	2022 MW Deficiency	# of Feeders	2022 MW Deficiency
Total Feeders	30,874	2,828	-	2,828	-
Overloaded Feeders in 2022	2,328	183	219	203	91
No Cost Transfers	1,799	147	144	144	70
Planned Investment	528	39	75	43	21
Candidate Deferral	394	26	26	--	--

**Values calculated in Table 8*

In other words, the counterfactual analysis does in fact increase the forecast of MW deficiencies in 2022. However, DERS caused only 21 MW of deferred distribution capacity, which is only 1.2% of the total 1,700 MW DER growth that is forecasted to occur during this time period (assuming the proportion of deficiencies that result in planned upgrades is similar for DERs embedded in the DER forecast as it is for the GNA). This relatively small impact is because most circuits are not close to being overloaded, and system-wide load growth is flat.

Although a power flow analysis is necessary to determine which circuits need distribution upgrades vs. being addressed with load transfers, the results of that study would likely result in a relatively small change in the total capacity of distribution system upgrades that were deferred through DERs—some circuits will realize higher demand than forecast, and other circuits will realize lower than expected demand, but in the absence of additional information, it is reasonable to assume as a first approximation that the discrepancy between over and under-forecasted capacity will balance each other out. While the simplified approach described above may significantly overestimate the deferred distribution, the scale of potential deferral remains low. This preliminary analysis suggests that the unspecified avoided costs of distribution attributable to non-targeted DERs are relatively small. A comprehensive analysis of the three IOUs will require a complete dataset of the IOUs' distribution system loading capacity in the submission of their 2019 GNA.

However, these results may change if building and transportation electrification creates substantial load growth that has not yet been accounted for in the IEPR forecast. In coming years, the CEC will have more information regarding the rates of electrification, with which the

Energy Division Recommendation on Unspecified Avoided Transmission Costs

At the December 20, 2018 workshop, Energy Division staff reviewed Parties' proposals for an avoided transmission cost, which were presented in the LNBA Long Term Refinements Working Group Report. There are several additional issues to those identified for distribution which add to the complexity of an avoided transmission cost value, particularly with regards to a locationally-specific transmission deferral value. These include, but are not limited to:

- **Generation and Transmission can serve as substitutes.** Transmission lines can replace generation capacity in local capacity areas and vice versa, so the avoided cost of transmission is highly specific to the individual transmission project, and the options for local capacity generation. Additionally, the value of local Resource Adequacy (RA) is subject to many additional factors, since energy is procured though many different energy markets so determining the avoided cost of transmission overlaps with avoided cost of generation.
- **Transmission capacity constraints are not as clearly defined as distribution capacity constraints.** Transmission needs the available capacity to meet "N-1 contingency", the condition in which the transmission system can meet the load under the condition that the nearest transmission or generation asset is offline. This need varies by location and depends on the shifting loading capacities of other neighboring circuits. Thus, there is not a constant, stable capacity value that is defined as a capacity overload for transmission as there is for distribution.
- **Transmission needs are planned for a 50-year asset.** Transmission planning is less about identifying and addressing a discrete capacity need in the near term, as distribution planning does, as it is about addressing long term population growth and generation supply.

Based on an examination of relative impact of DERs on the demand forecast at the busbar level, staff estimates that as with the distribution capacity deferred by DERs, the transmission capacity that is deferrable by DERs is likely a small fraction of the total marginal cost of transmission. For this reason, staff finds that the avoided cost of transmission is likely be to be substantially less than the marginal cost of transmission. One option for inclusion in the ACC may be to apply a derate factor to the marginal cost of transmission to reflect factors such as those discussed above.

As for the calculation of the marginal cost of transmission, PG&E has provided such in its recent GRC Phase II filings. Their transmission marginal cost is based on the capacity-driven projects in their transmission plan and is estimated using a method similar to that used for their marginal costs for distribution. Staff believes that SCE and SDG&E should be able to execute similar calculations based on their respective transmission plans without excessive burden. To be clear, staff is recommending calculation of marginal costs for peak demand changes to the utility base forecasts. Staff is not suggesting at this time that the utilities create new transmission plans and investment forecasts based on alternate load forecast, as was discussed by some parties in the LNBA Working Group.

Staff seeks further input from parties to either explore this approach, further refine parties' current proposals, or examine other potential data sources upon which to base avoided cost of transmission, such as locational marginal pricing.

5. Energy Division's Proposed Approach on Specified Transmission and Distribution Deferral Value

While the scope of this paper deals explicitly with methodological approaches to calculate unspecified T&D deferral vales, Energy Division believes it is important to also point out preferred approaches to apply specified deferral values in other venues. PU Code Section 1002.3 states that the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, and other demand reduction resources.

The Commission is addressing this requirement by expanding this DIDF process to include transmission projects that are under CPUC jurisdiction, as was required in the May 7, 2019 *Administrative Law Judge's Ruling Modifying the DIDF Process*. For establishing and monetizing specified avoided distribution costs, Energy Division propose to apply the values resulting from the annual DIDF process, and through potential new DER tariffs under consideration in IDER, not the avoided cost calculator. The DIDF process is currently in its 1st 2018 cycle with new solicitations underway. Based on a review of stakeholder input on how to further refine and improve the DIDF process and framework, the Commission issued a Ruling to implement certain improvements to the DIDF process and framework. One such change is starting in 2019, the IOUs will include transmission projects that are subject to CPUC jurisdiction in their annual GNA and DDOR filings for consideration as possible deferral opportunities. The Commission will continue to implement, refine and improve the DIDF as well as incorporate lessons learned in the IDER pilots, and is currently evaluating proposals for DER tariffs in the IDER proceeding, which are based on the specified distribution deferral opportunities identified in the GNA and DDOR.

For specified avoided transmission, the California Independent System Operator (CAISO) have expressed their commitment to identify and consider non-wire alternatives across the entire transmission and distribution system. CAISO has integrated non-wires alternatives into their Transmission Planning Process (TPP).[18] Each year, CAISO conducts its TPP to identify potential system limitations as well as opportunities for system reinforcements that improve reliability and efficiency. The TPP core product is the CAISO Transmission Plan, which provides an evaluation of the CAISO control grid, examines conventional grid reliability requirements and projects, summarizes key collaborative activities and provides details on key study areas and associated findings. For each planned transmission project CAISO considers non-wires alternatives and this can sometime result in solicitation of DERs as transmission alternatives. An example of this is the Oakland Clean Energy Initiative where PG&E and East Bay Community Energy are actively procuring DER solutions to replacing aging gas power plants in Oakland, CA to avoid the need to build new transmission lines to serve the Port of Oakland.

Commission staff recently incorporated consideration of non-wires alternatives into the review of a proposed new transmission projects, the SCE Application (A. 15-12-007) for a Permit to Construct Circle City Substation and Mira Loma-Jefferson Sub-transmission Line Project. Certain transmission projects authorized as needed through the TPP trigger a California Environmental Quality Act (CEQA) review which involves an application to the CPUC. The CEQA process provides for the study of alternatives to the infrastructure project under study if the alternative can lessen or eliminate a significant environmental impact. In the cases above the CPUC is considering battery storage alternatives to building new transmission assets.

To date the number of times DERs are procured as substitutes for planned transmission projects is very limited, but recognition of the potential is increasing. Several jurisdictional, planning and analytic issues must be addressed if there is to be more use of DERs as alternatives to planned transmission projects.

[18] The CAISO 2019-2020 Transmission Planning Process Final Study Plan issued on April 3, 2019 states "If reliability concerns are identified in the initial assessment, additional rounds of assessments will be performed using potentially available demand response and energy storage to determine whether these resources are a potential solution. If these preferred resources are identified as a potential mitigation, a second step - a preferred resource analysis may then be performed, if considered necessary given the mix of resources in the particular area, to account for the specific characteristic of each resource including use or energy limitation in the case of demand response and energy storage." Pg. 24

6. Recommendations

In consideration of the large body of information previously provided by parties both on the record of the DRP proceeding as well as informally, staff provides the following recommendations regarding the locational granularity of transmission and distribution avoided costs for the various potential use cases that were identified in Section 2. To provide context for these recommendations, we first review the current or proposed methods for calculating each type of deferral value and category of use case, and the level of uncertainty in each. Since the procurement use cases involves monetizing the transmission and distribution deferral value, the threshold for reliability in the results needs to be higher than for the planning use case.

Assessment of Uncertainty in Deferral Values as Applied to Types of Use Cases

1. **Specified Distribution Deferral Value**

- **Planning Use Cases:** The specified distribution deferral value is currently developed and applied in DIDF process through the LNBA, and the level of uncertainty for the circuit level values should be acceptable for all planning use cases, including IRP.
- **Procurement Use Cases:** The specified deferral values are currently quantified at the circuit level of granularity in the DIDF procurement process for the DIDF procurement use case. This calculation has a reasonably high degree of certainty, as they are continually updated in the annual distribution planning process, and the IOUs will bring the locational granularity to the sub-circuit/nodal level in 2019. Other procurement use cases, e.g., DER tariffs, may use these values, as long as they are for separate locations from projects that are included in the DIDF solicitations.

2. **Unspecified Distribution Deferral Value**
Section 4 on the limitations of the staffs' preliminary analysis explained how the determination of which circuits may be addressed using no-cost load transfers and which would require distribution system upgrades is highly uncertain. Reducing this uncertainty would require a powerflow analysis using counterfactual load data. Staff does not find that the effort required is justified by the size the of the potential distribution deferral. Furthermore, there would still be a significant amount of uncertainty in a powerflow analysis on a counterfactual forecast, since minor changes in load growth would result in the powerflow analysis being inaccurate.

- **Planning Use Cases:** It may be possible to derive an unspecified distribution deferral value at the substation/feeder bank level that improves the certainty of these values. ED staff has not attempted to do this analysis, as it may require consultant technical support to develop and incorporate the calculations into the LNBA and IRP capacity expansion models. Given the small scale of potential distribution deferrals that can be anticipated to result from this analysis, ED staff would suggest that the effort to disaggregate the distribution deferral value in these models is not justified but seeks input from the parties on this position. At this time, ED staff recommends that the granularity of unspecified distribution deferral value be applied at the system level.

- **Procurement Use Cases:** As with the planning use case, an aggregation of deferral value may be useful at the substation/feeder bank if highly loaded feeders are clustered together. As such, a locational tariff may be useful to defer distribution in areas where there are limited opportunities to transfer load and reconfigure the grid, and a GNA-based analysis may serve this use case. However, given the potential for shifting of loads between feeders, staff does not find a locationally granular breakout of distribution deferral value to be well suited to the avoided cost calculator. The avoided cost calculator values are updated annually at best, and must be used for many different use cases, including to establish the energy efficiency portfolio budgets. The uncertainty of the shifting locations of distribution needs does not align well with the use cases for the avoided cost model, like EE portfolio budget setting. Therefore, the staff recommends that granularity of unspecified distribution deferral value be applied to the avoided cost calculator at the utility territory level as a uniform value.

3. **Specified Transmission Deferral Value**
Calculating the value of DERs to meet specified transmission deferral needs should be addressed in the Transmission Planning Process if they are under CAISO jurisdiction. The CPUC DIDF process has recently expanded to cover transmission upgrades that are CPUC jurisdictional. Both processes are relatively new and can benefit from learning and improvement.

4. **Unspecified Transmission Deferral Value**
The amount of uncertainty associated with the location of unspecified transmission value is extremely high, as discussed in Section 4. It may be possible to include a locational granularity that is below the system level, as SCE proposes in their workshop presentation, dividing the utility territory into import, export and neutral zones. Staff does not find that the amount of value that may be attributed to these zones would justify adding the complexity to the avoided cost calculator, LNBA or IRP capacity expansion models.

Recommended Methodology for Transmission and Distribution Deferral Value

Staff's recommendations for estimating distribution deferral value mirrors, at a high level, the approaches of PG&E and NY as presented at the December 2018 workshop (see Appendix B). Specifically, staff proposes to divide distribution deferral value into both locationally granular and non-granular components based on whether the deferral value is specified or unspecified. For the locationally granular component, staff proposes that values associated with the DIDF process be used, consistent with PG&E's proposal. For the non-locationally granular component, staff proposed to use data derived from DIDF, but modified to reflect a quasi-counterfactual[19] future in which forecasted DERs are not installed.

Table 5 below summarizes staff's recommendations for methodology and the level of granularity for each type of deferral value, along with the rationale for each.

[19] "Quasi-counterfactual" reflects the fact that the deficiencies are estimated not based on power flow analysis but based on a simplified extrapolation of original power flow analyses used to generate the GNA.

Table 5. Staff Recommendations for Transmission and Distribution Deferral Value Methodologies and Locational Granularity

Value	Existing process to calculate value	Recommended Methodology	Recommended Granularity of Final Value	Rationale for Recommended Methodology
Specified distribution deferral value	DIDF	Continue DIDF/GNA/DDOR	Location-specific as identified in DIDF	Consistent with existing distribution planning methods that underly traditional investments.
Unspecified distribution deferral value	Marginal cost from GRC applied through PCAF method and annual updates to Avoided Cost Calculator	Energy Division GNA-based counterfactual analysis	Climate Zone or Utility territory	The GNA data can provide more accurate analysis of the direct impact of DERs on the circuit level, which in aggregate is relatively reliable, but which specific feeder upgrades will be deferred is more uncertain
Specified transmission deferral value	CAISO TPP identifies the transmission needs but does not determine the costs. CPUC CEQA Applications also consider NWAs as environmental alternatives.	Continue to use the CAISO and CPUC methods. CPUC DIDF to begin to include CPUC jurisdictional transmission in 2019	Location-specific as determined by each project	Consistent with existing TPP process, existing DIDF process, and existing CEQA process.
Unspecified transmission deferral value	Annual CPUC updates to Avoided Cost Calculator	None at this time	Utility territory	More granular values cannot be calculated with acceptable certainty.

Recommendations Regarding Implementation of Unspecified Distribution Deferral Value in ACC

To implement the use case of the GNA and DDOR data to identify utility-wide unspecified distribution deferral value, Commission staff recommend that the IOUs be required to take the following steps:

1. Analysis for distribution deferral value should be conducted using the 2019 GNA, to include facilities that were not included in the 2018 GNA
2. A counterfactual hourly load forecast should be developed by adding the hourly load impact of the DER forecasts included in each utility's GNA. This process should account for the shapes of the underlying DERs.
3. Demand reduction from non-targeted and DER growth driven by codes and standards should be kept in the counterfactual forecast
4. Deficiencies across the utility's distribution system should be assessed assuming the new load forecast through simplified extrapolation exercise, rather than a detailed power flow analysis.

5. Deficiencies that can be addressed at low or no cost, without the use of significant new infrastructure investments should be removed.
6. Deficiencies that cannot be deferred using DERs should be removed.
7. The cost of any remaining deferrable infrastructure investments should be summed across the utility territory to represent the aggregate unspecified distribution deferral value.

The resulting utility-wide number would then be available for incorporation into the avoided cost calculator, or other tools, for application in any use case. The specified and unspecified distribution deferral values would be additive.

(END OF ATTACHMENT A)

(END OF ATTACHMENT A)

APPENDIX B

APPENDIX B

Workshop on Improving the Transmission and Distribution Values in the Avoided Cost Calculator December 20, 2018

Workshop Agenda
R. 14-08-013: Considerations in Developing a Methodology for Locational Avoided Cost of Transmission and Distribution

December 20, 2018, 10 am to 4 pm
Courtyard Room
Conference Line (866)830-4004, Passcode 986 9619
(Add Webex info)

10:00-10:30	**Introduction**	**30 min**
	Presentation on background of the LNBA, and considerations in applying locational value in the avoided costs calculator	Dina Mackin, Fred Wellington
10:30-11:20	**Avoided Distribution Methodology Discussion**	***50m***
	Presentation on current calculations used in the ACC	Snuller Price, E3
	PG&E's proposal the Marginal Cost of Distribution Capacity from their GRC, with a locational adder	Rick Aslin, PG&E
	Energy Division Alternate Conceptual Approach: Application of data from the Grid Needs Assessment to calculate a simplified circuit level avoided distribution capacity value	Fred Wellington, Energy Division
11:20-11:30	**Break**	***10 min***
11:30-12:30	**Discussion on Distribution Cost Methods**	***60 min***
12:30-1:30	**Lunch**	***60min***
1:30-2:20	**Avoided Transmission Methodology Discussion**	***50 Min***
	Energy Division Summary and Considerations of the Approaches to Estimating Location Avoided Cost of Transmission	Dina Mackin, Energy Division
	SCE's Proposed Methodology on Locational Avoided Cost of Transmission	Maurice Ahyow, SCE
	SEIA's Proposed Methodology for Applying Marginal Cost	Tom Beach, SEIA
	CAISO Discussion of Potential Application of Local Capacity Requirements for Avoided DERs	Delphine Hou, CAISO
2:20-2:30	**Break**	***10 min***
2:30-3:30	**Discussion on Transmission Cost Methods**	***60 min***

3:30-4:00 Conclusion and Next Steps ***30 min***

Workshop on Improving Transmission and Distribution Values in Avoided Cost Calculator

Energy Division
December 20, 2018

Workshop Objectives

- Discuss issues so that Parties can provide more actionable comments to a Ruling to be issued in January on topics discussed today.
- To consider the IOU proposals (dated Dec 5, 2017) in terms of forecast uncertainty, modeling complexity and appropriate level of modeling effort as a function of the manner in which the resulting value would be used.
- To consider whether there is an avoided T&D cost method that is accurate enough to inform resource sourcing on a locational basis.

DRP Proceeding Background

P.U. Code 769 established the following requirements that an avoided T&D calculation must inform:

(b)(1) Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provide to the electrical grid or costs to ratepayers of the electrical corporation.

(b)(2) - Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives; and

(b)(3) - Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.

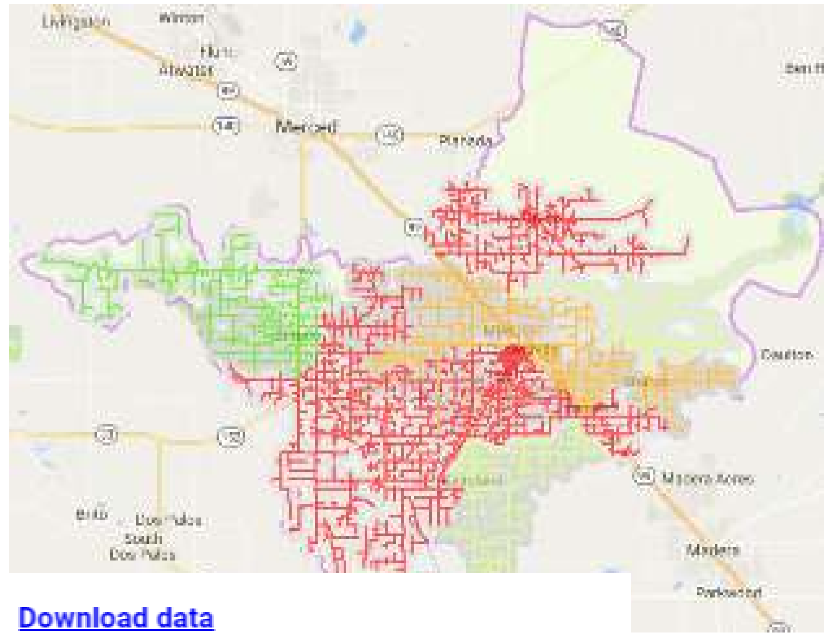
DRP Proceeding Progress to Date

DRP Activities	Objective	Progress to Date
Locational Net Benefits Analysis (LNBA)	• To evaluate and quantify the locational benefits of DERs	• Initial Methodology adopted and Demo Project B implemented in 2017. • System-wide rollout December 2018
Integration Capacity Analysis (ICA)	• To calculate hosting capacity for DERs at all locations in order to streamline interconnection	• Initial Methodology adopted • Demo Project A implemented in 2017
Distribution and DER Forecasting	• To determine how DER growth is forecasted and reviewed	• Adopted methodology and updated process
Distribution Investment Deferral Framework (DIDF)	• Establish process to identify and procure DERs to defer Dx upgrades where feasible	• Adoption and Implementation of DIDF in 2018 • Advice letters filed in Nov 2018
Grid Modernization Framework	• To identify spending necessary to integrate DERs into distribution system	• Adopted Framework • PG&E to file first Grid Mod Plan by 2018 • Planned to inform GRCs

Background on Locational Net Benefits Analysis

- LNBA Working Group developed the LNBA adopted in D.17-09-026, which informed two use cases:
    1. Public tool and heat map to inform developers of deferral opportunities
    2. Prioritization of candidate deferral projects identified in the DDOR
- Decision affirmed a third use case that is not met by current LNBA tool:
    3. "to develop a comprehensive quantification of DER value at any location on the distribution grid for IDER sourcing and cost-effectiveness evaluations, informing DER incentive levels, providing distribution-level costs and benefits information to IRP, and other potential related applications."

Example of LNBA Public Tool



Download data

Circuit Number:	252451103
Circuit Name:	EL NIDO 1103
DER ShortTerm:	-0.232
DER MediumTerm:	-0.398
DER LongTerm:	-0.55
LNBA ShortTerm:	$$$$
LNBA MediumTerm:	$
LNBA LongTerm:	$
Deferrable:	El Nido 1103 Reconductor [illegible]

IOU Proposals for the Avoided Cost Calculator

- To meet this third use case, the IOUs were directed to submit proposed methodologies to provide locational values for the avoided cost calculator based on:
  – T&D spending for a 30-year window, consistent with the useful life of DERs
  – Deferred Dx capacity occurring from DER growth that is embedded in the demand forecast from exiting tariffs and programs
  – Include DER integration costs
  – Disaggregated at the Distribution Planning Area level

PG&E's Proposal

- Bifurcate DPA marginal Dx capacity cost into base and project specific values
- System-level avoided cost applied to base
- Specified deferrals calculated avoided cost based on 4 "Rs"
- Does not include a method for counterfactual analysis
- Include DER integration costs
- Does not conform to Track 1 decision

SCE's Proposal

- Divide service territory into areas based on sub-Tx interface
- Use a streamlined planning method to create 30-year counterfactual Dx avoided cost
- Need to remove each DER from the forecast to run planning analysis to determine each DER impact on grid
- DER integration costs based on Grid Mod data
- Conforms to Track 1 decision

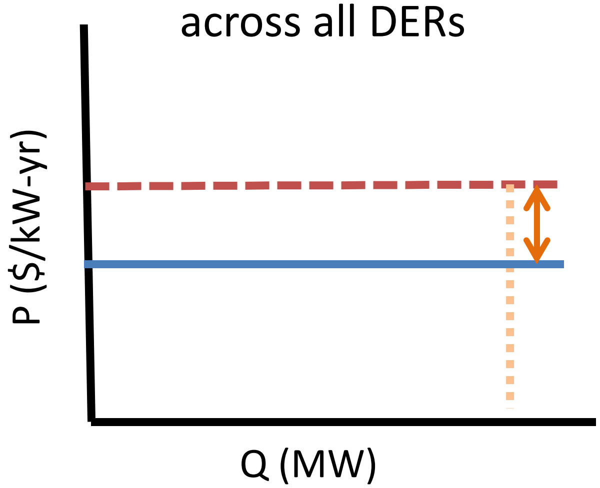
SDG&E's Proposal

- Did not submit a proposal, because SDG&E states that LNBA showed that different DER scenarios resulted in minimum change in value.
- Does not conform to Track 1 decision

How Avoided T&D Costs are Currently Calculated in the Avoided Cost Calculator

Avoided Cost Calculator (ACC)

Marginal avoided T&D capacity cost applied evenly across all DERs



DER production cost

Avoided T&D capacity cost

DER net cost

- Based on marginal costs from past GRC
- Value is applied on a system-wide basis which inherently assumes DERs avoid the same level of T&D regardless of location
- Marginal avoided T&D capacity cost is applied based on DER load shape coincidence by climate zone
- Assumes T&D cost is allocated to hourly load shape of distribution load profile

<u>Limitations of this method</u>:

- DERs do not defer all distribution costs, so marginal cost overestimates the avoided cost
- Some quantity of DERs will provide high value for deferring Dx upgrades
- Other DERs will provide no value or incur additional costs to the system

Difference Between LNBA Calculator and Avoided Cost Calculator

T&D avoided cost methodology depends on the use case

Specified Deferrals: Locational Net Benefits Analysis

Use Cases:

1. Identify circuit-specific, DER procurement opportunities based on near term needs
2. Evaluate DER proposals for short-term Dx deferral projects via DIDF

Avoided cost calculation:

- Reflects deferral opportunities under trajectory stress conditions defined by IEPR forecast
- Is limited to the circuits with DIDF candidate deferral projects selected for competitive solicitation

Unspecified Deferrals: Potential Modifications to ACC

Use Cases:

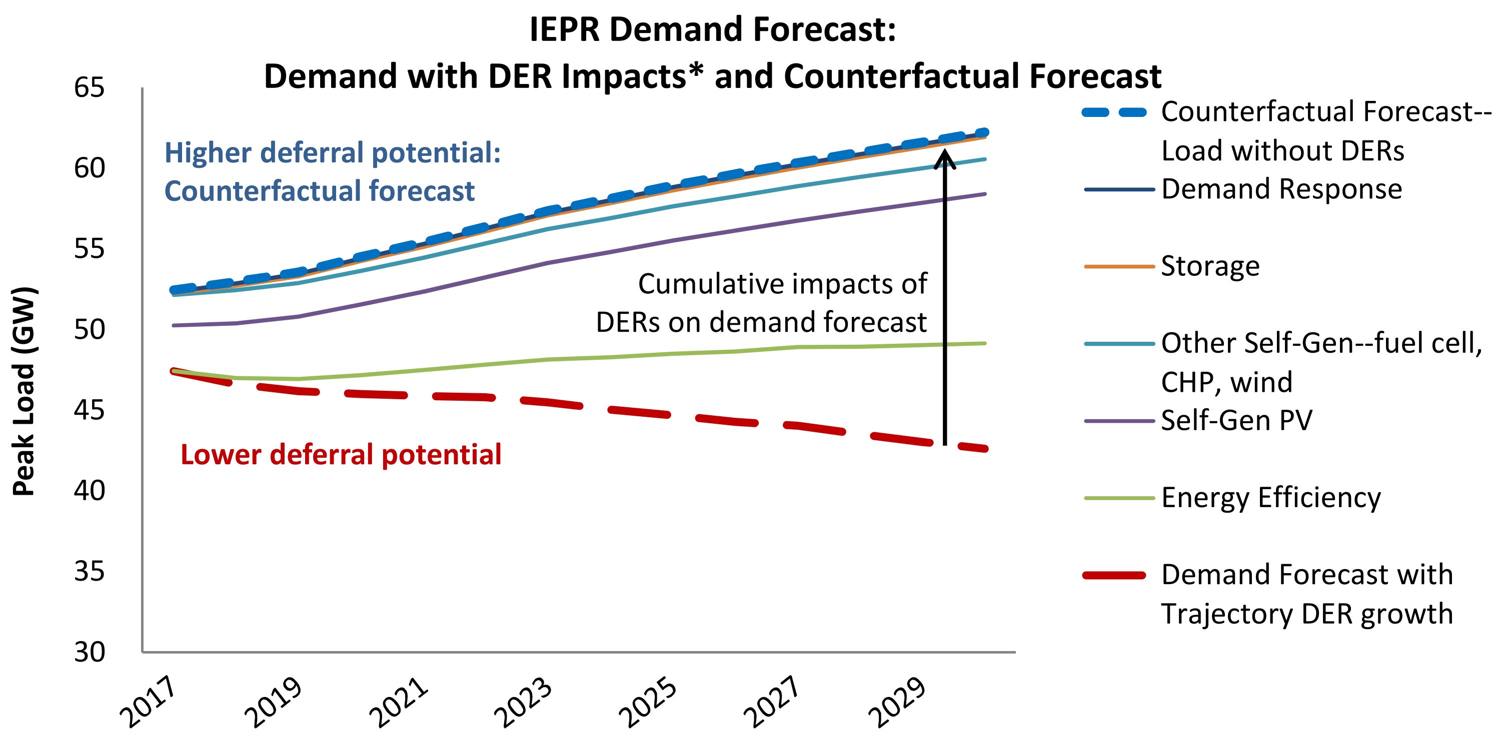
1. Inform long-term DER programs and policies
2. Potentially establish location-specific tariffs
3. Provide T&D impacts of DERs to IRP modeling for meeting GHG targets

Avoided cost calculation:

- Reflects the deferred Dx costs that results from DER growth that is embedded in the forecast due to existing programs and tariffs
- Should include DER integration costs

Limitations of Current LNBA for Avoided Cost Calculator Use Case

- The chart below is the CEC demand forecast—the red, downward sloping curve reflects the forecast with DER growth, which is used for Dx planning
- LNBA adopted in Track 1 decision calculates the Dx deferral potential based on the demand forecast
- Different demand trajectories will produce very different avoided T&D values



*Non-coincident peak load

Forecast simplified for illustrative purposes. Actual counterfactual forecast must be adjusted for Codes and Standards and peak shift, and impact of EVs is included in forecast but not shown on this chart

Track 1 decision identified a need for counterfactual Dx planning analysis*

- SCE submitted a proposal that conformed to the requirements of the Track 1 Decision to calculate the avoided T&D capacity of the counterfactual forecast
- Methodology requires the IOUs to conduct an alternate Dx planning analysis based on the counterfactual forecast

Dx planning process based on a counterfactual forecast

1. System Level Forecast

Apply counterfactual forecast
+
Circuit level forecast disaggregation

2. Grid Needs Assessment

Powerflow analysis to identify distribution system deficiencies to determine grid needs
+
Analyze for potential load transfers for no cost solutions

3. DDOR

Identify potential grid upgrade projects based on typical dist. upgrades and costs
+
Identify upgrades that can be deferred with DER shapes

5. Cost analysis

Determine costs of traditional wires solutions
=
Total forecasted T&D cost and MW of potential DERs to defer system upgrades from counterfactual forecast

*Commission was seeking a similar approach to calculate avoided Tx capacity cost

Challenges with Counterfactual Dx Planning Analysis

- While SCE’s proposal conformed to the Track 1 Decision, Energy Division’s assessment of the need for a “counterfactual planning analysis” may not be practical for the following reasons:
  - Number of annual deferrable upgrades is relatively small, so conclusions are highly subjective
  - Dx planning analysis involves judgement of IOU distribution engineers, whose priority is maintaining grid reliability
  - The range of possible outcomes in circuit-level DER forecast leads to a degree of uncertainty subsumes the results

Therefore, this workshop considers methods of applying marginal costs.

Discussion Questions
➢ Do parties find it reasonable to focus on developing an avoided cost methodology that uses marginal costs?

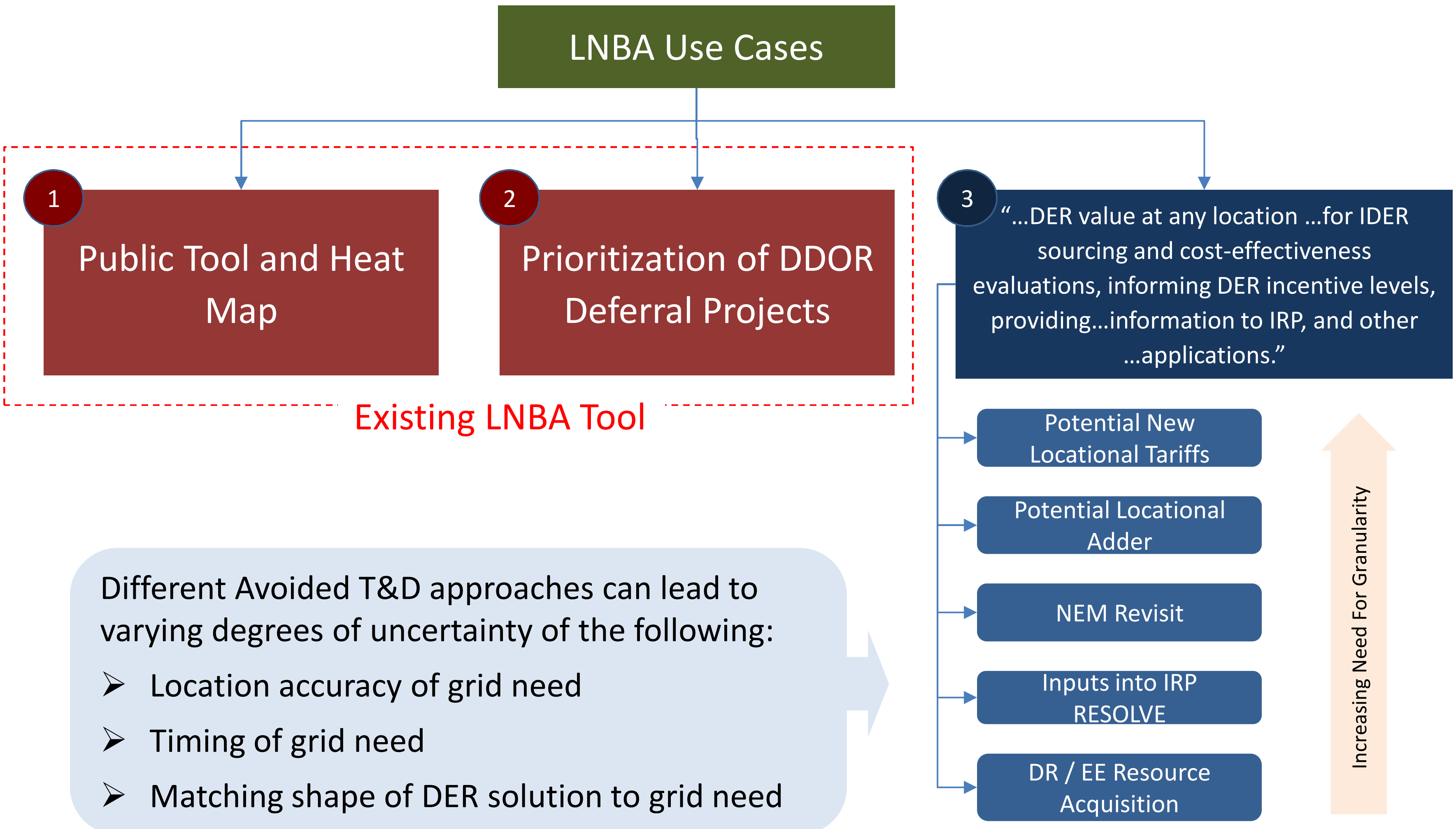
Considerations on how Locational Values Will be Calculated and Applied

- DER costs and benefits depend on load forecast and the DER resource mix embedded in that forecast
- Uncertainty in this forecast can lead to discrepancies between the actual future load and what was forecasted - both in terms of load levels and location on the grid
- This uncertainty can lead to a mismatch between the specific location of the grid need and a potential DER solution

Discussion Questions

- Threshold Question: Is there an approach to calculating locational avoided T&D cost that can be relied on to inform DER tariff structure(s) so that the grid need is addressed by the right DER, in the right place at the right time.
- What is the appropriate level of uncertainty that is acceptable in this process?

Use Cases of Locationally Specific Avoided T&D Value Influence the Requisite Methodology



END

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Methodology for Avoided T&D Costs

CPUC Workshop

December 20, 2018

Snuller Price, E3

Presentation Outline

- Overview of the current T&D avoided cost methodology in the ACC and LNBA tool
- Targeted deferrals vs. system wide programs
- Examples from other jurisdictions
  - BPA transmission planning process
  - New York VDER Tariff
- Additional considerations putting a plan together
  - “Nested” areas and CAISO LCR zones, priority
  - Developing the counterfactual

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EXISTING T&D METHODOLOGY IN THE ACC AND LNBA TOOLS

Two Different Use Cases

Targeted Deferral (iDSM) → Specific projects that are candidates for deferral based on DDOR screening.

T&D Avoided Cost Estimate → Value of T&D capacity for untargeted programs.

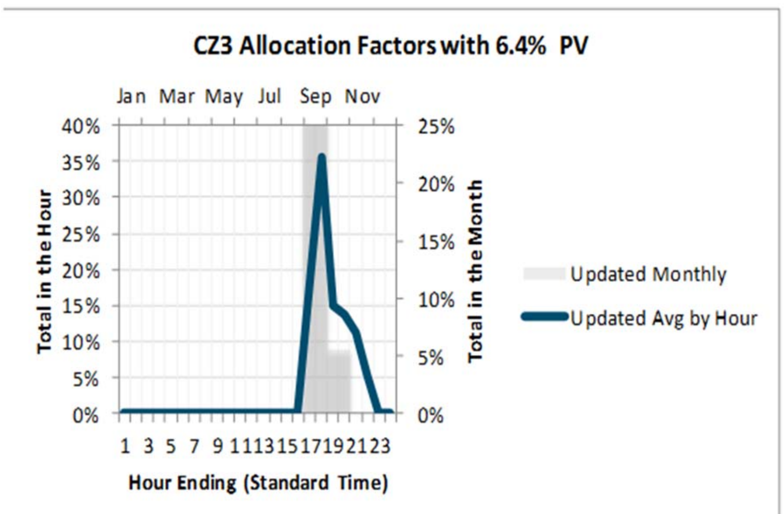
T&D Avoided Capacity Costs - ACC

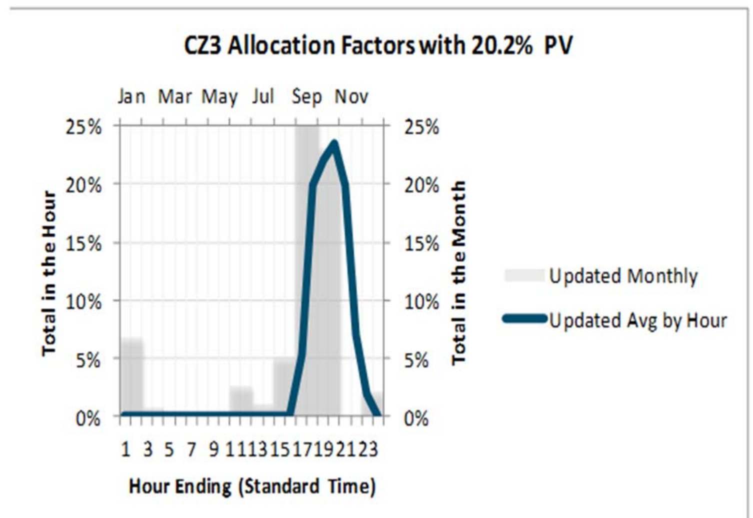
+ Based on 2015 GRC filings for SCE and SDG&E, 2014 GRC for PG&E

- SCE: $129.82/kW-yr ($2015)
- SDG&E: $100.02/kW-yr ($2016)
- PG&E: $97.12 - $152.29/kW-yr ($2014, vary by Division)

+ Allocated to hours based on hourly regression forecast of distribution demands net of PV generation

- Allocations vary over time with increased PV generation

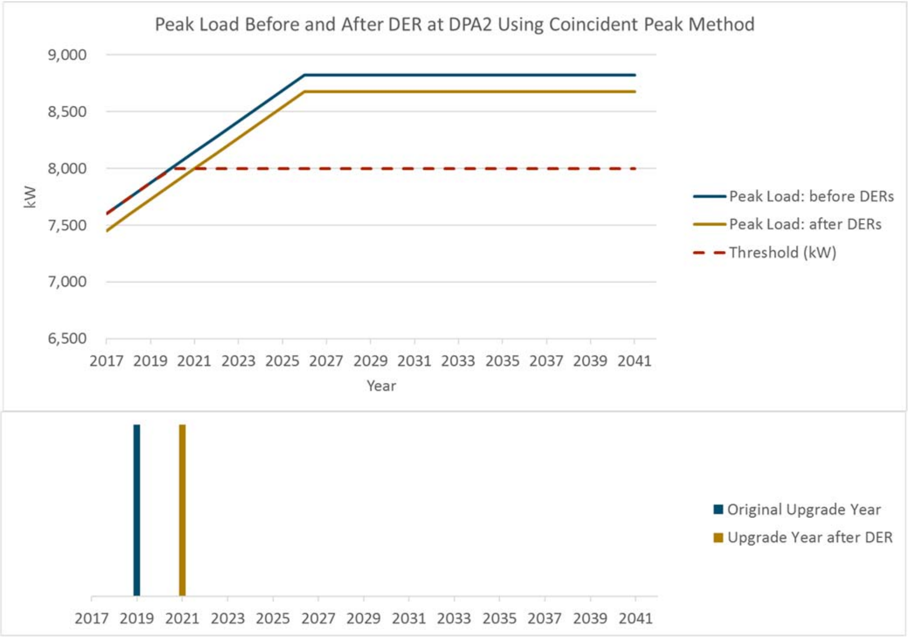




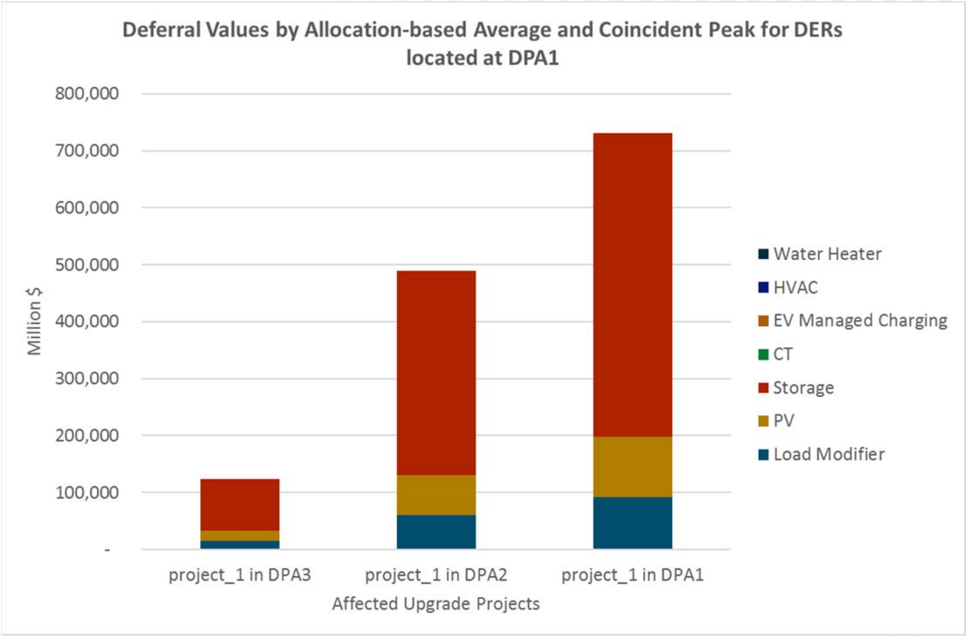
LNBA Tool – DDOR

- **Project Specific Valuation**
- **Deferral is the avoided costs to ratepayers using differential revenue requirement method and achievable peak load reduction**

Upgrade Project Evaluation



Deferral values summary



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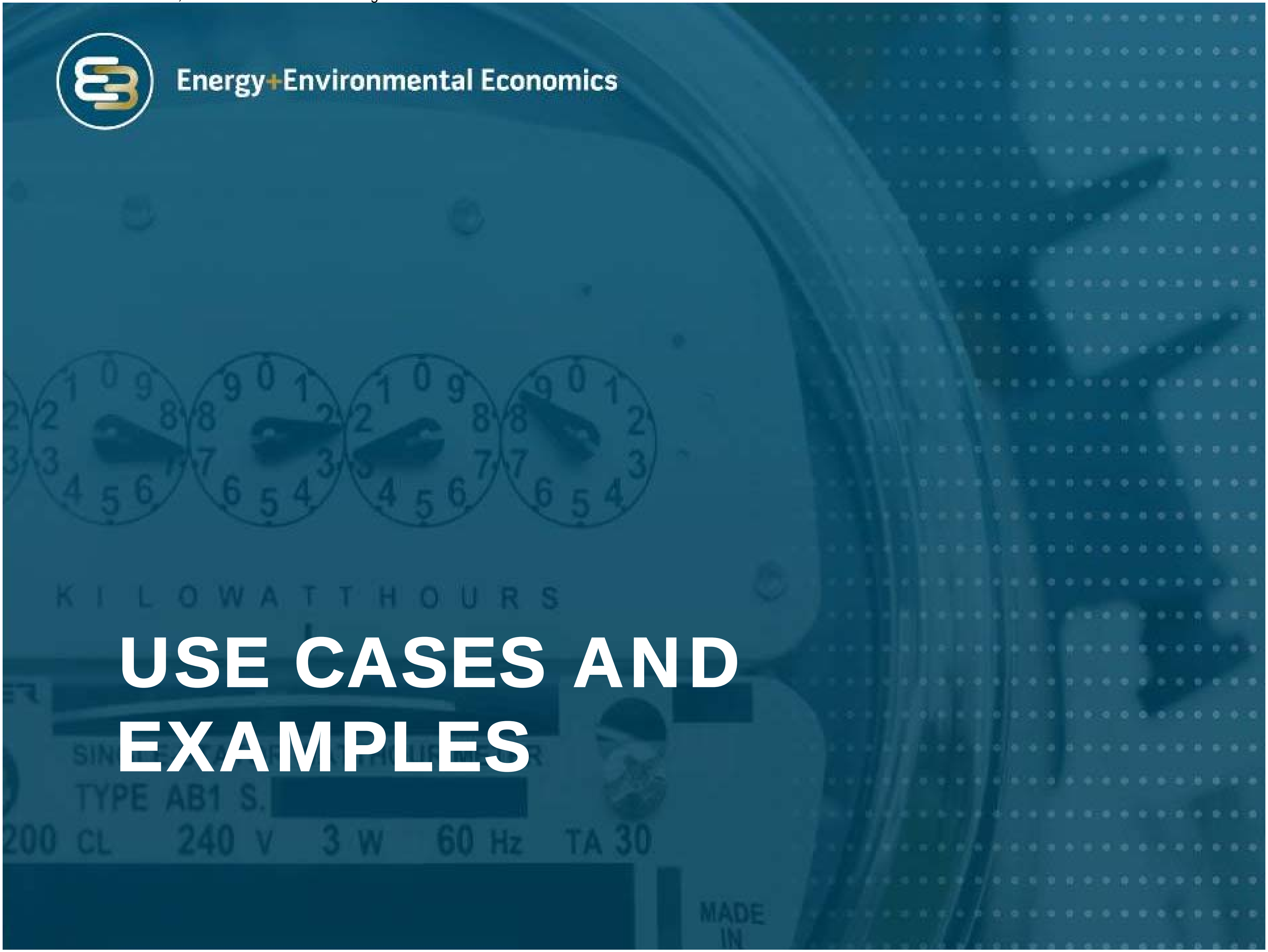
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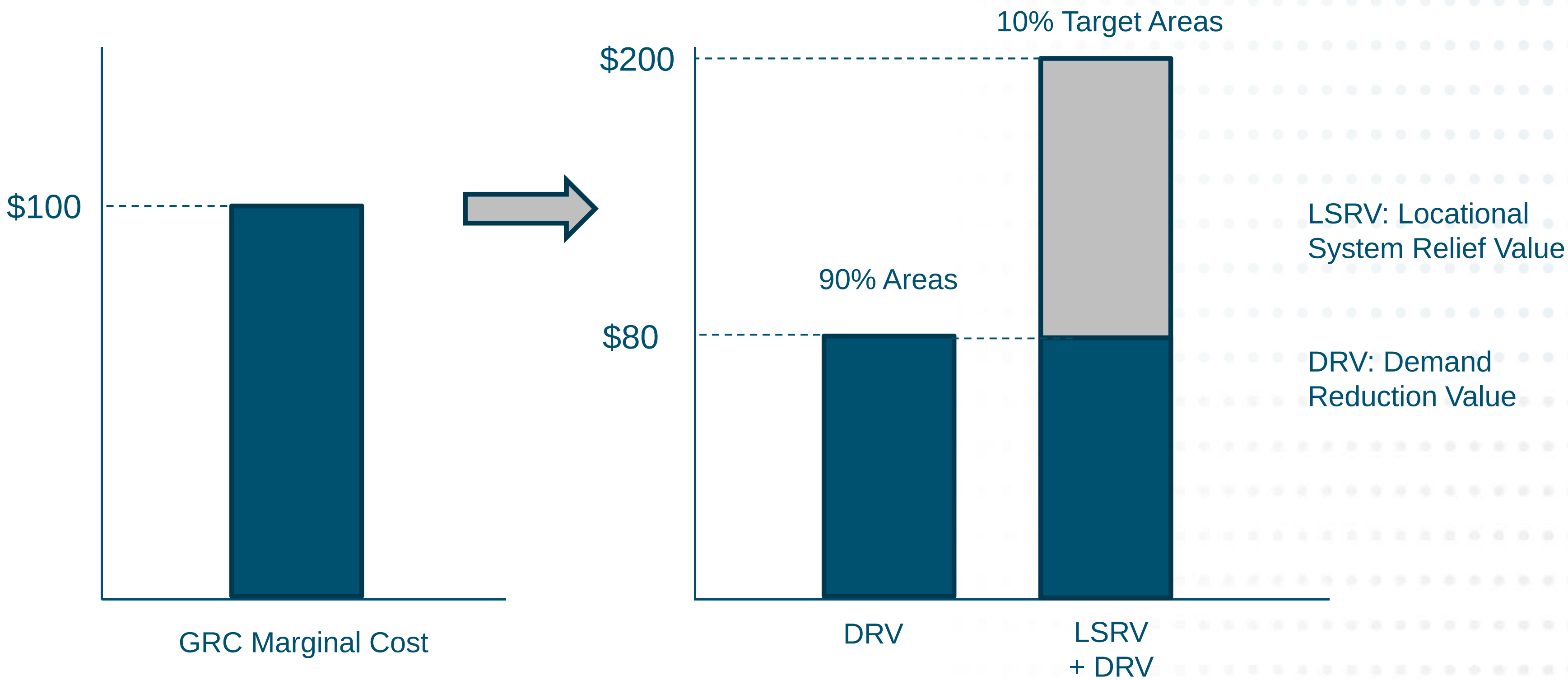
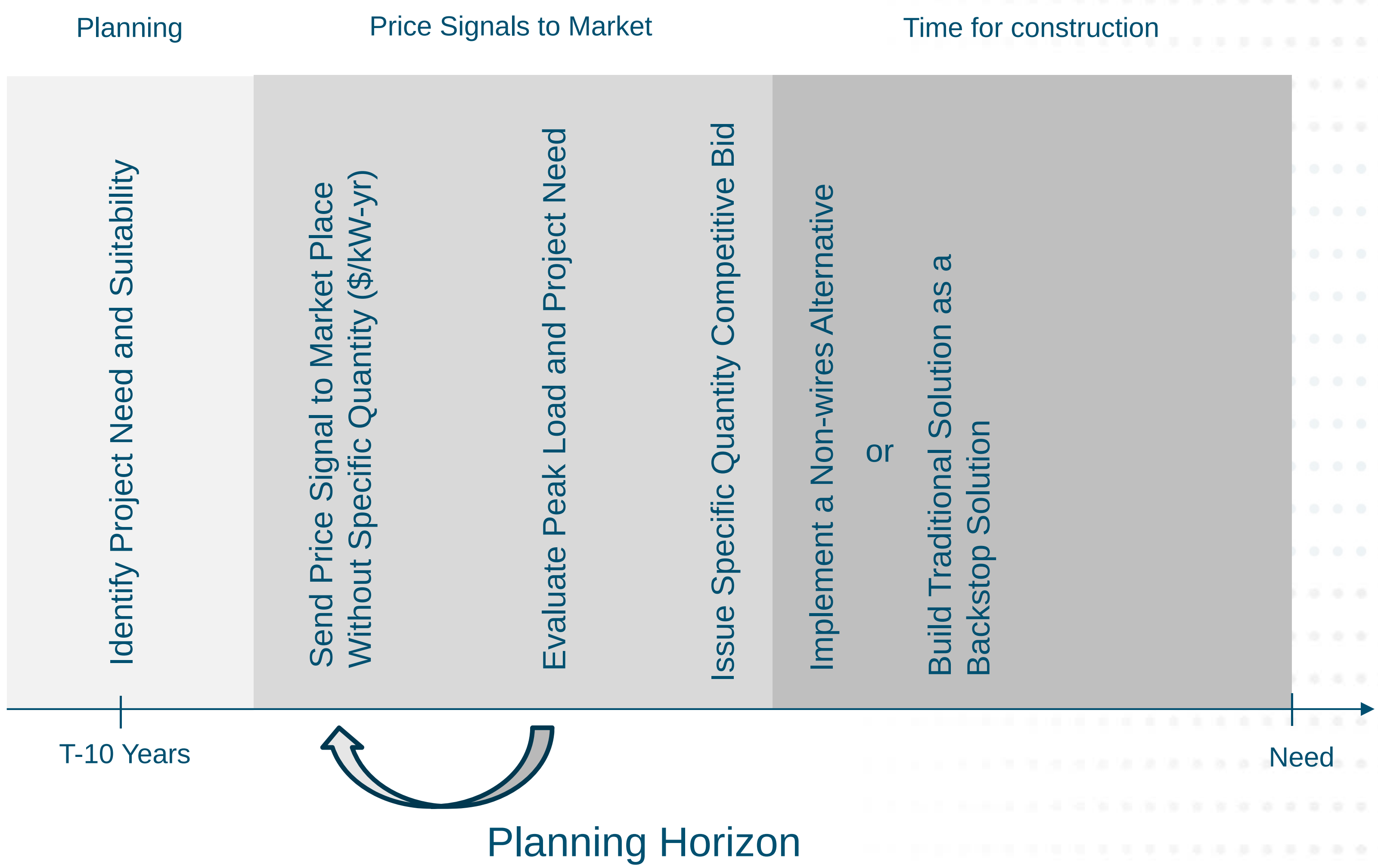
USE CASES AND EXAMPLES

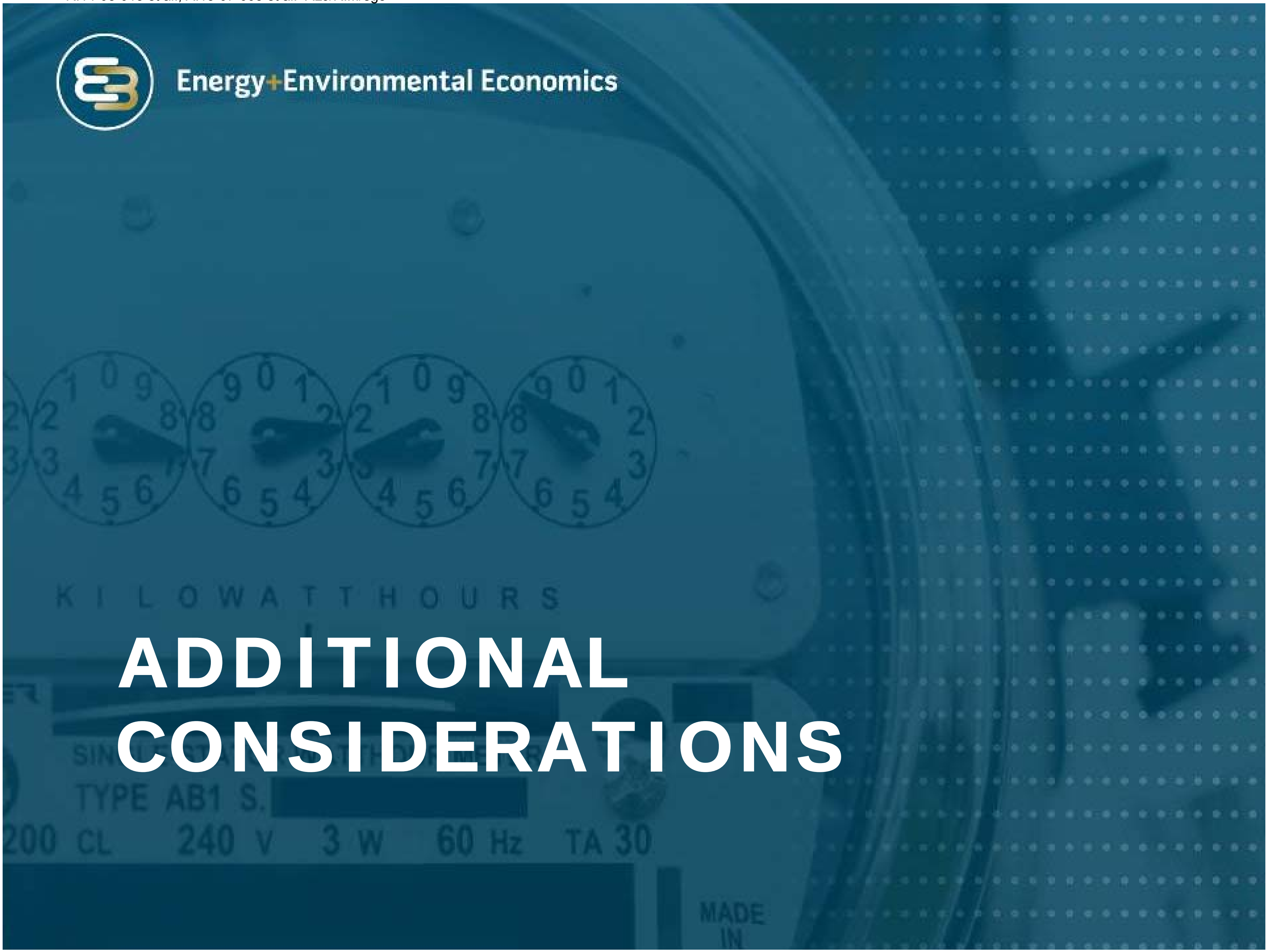
New York VDER Tariff Example

- The VDER Tariff design links the specific areas with identified needs and the non-specific distribution avoided costs



BPA Non-Wires Process Concept

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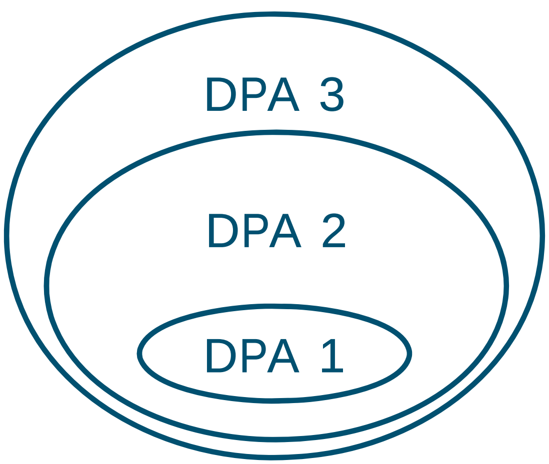
ADDITIONAL CONSIDERATIONS

"Nested" Areas and Priority

- Some points on the system are downstream of multiple constraints, for example, constrained distribution system in a constrained LCR zone
- Capturing multiple value streams means accounting for the certainty in being able to provide kW reductions, storage dispatch gets complicated by priority. Coincidence of constrains is important



Flow Factors

Distribution Network Mapping Flow Factors

DER Location ↓	flow factor	Wires Equipment Location → DPA1	DPA2	DPA3			
	DPA1	100%	100%	100%			
	DPA2	0%	100%	100%			
	DPA3	0%	0%	100%			

Loss Factors

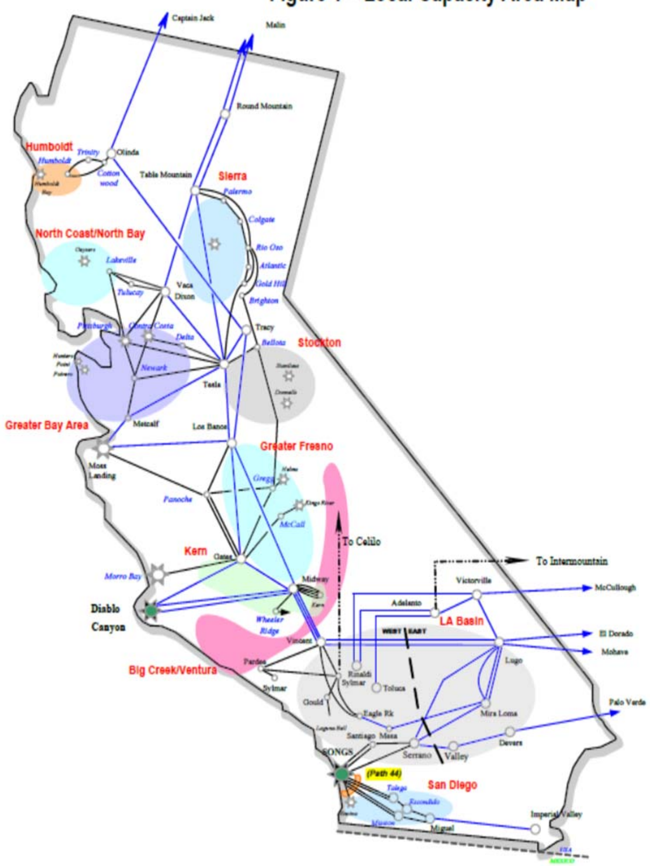
Distribution Network Mapping Loss Factors

DER Location ↓	loss factor	Wires Equipment Location → DPA1	DPA2	DPA3			
	DPA1	100%	105%	110%			
	DPA2	0%	100%	105%			
	DPA3	0%	0%	100%			

CAISO LCR Zones

+ **CAISO LCR Map – 2018 Study**

Figure 1 – Local Capacity Area Map



+ **Potential approaches to value load reduction in LCR Zones**

+ **Avoided costs**

- Avoided cost of new capacity resources
  - Net cost of CT
  - New transmission (similar to distribution system)
- Avoided cost of existing resources
  - Avoided reliability must run contracts within the zone

+ **Allocation by time of year**

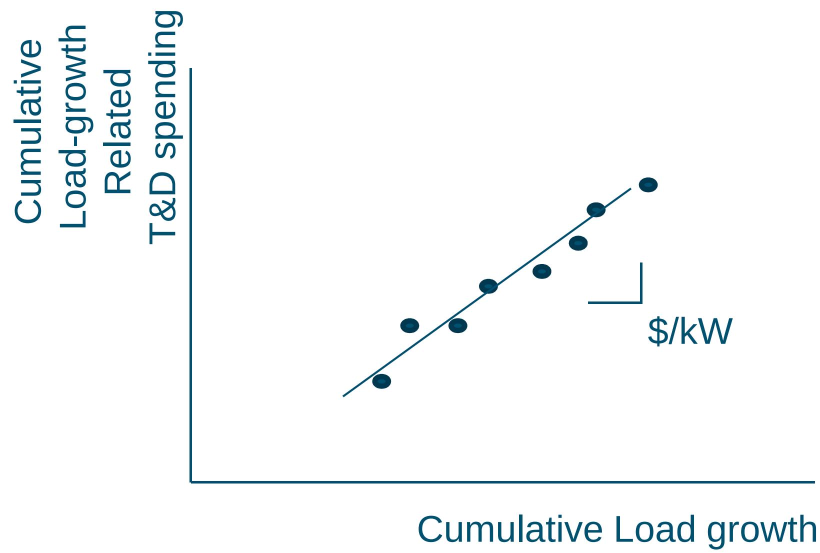
- Load shape in area (PCAF)

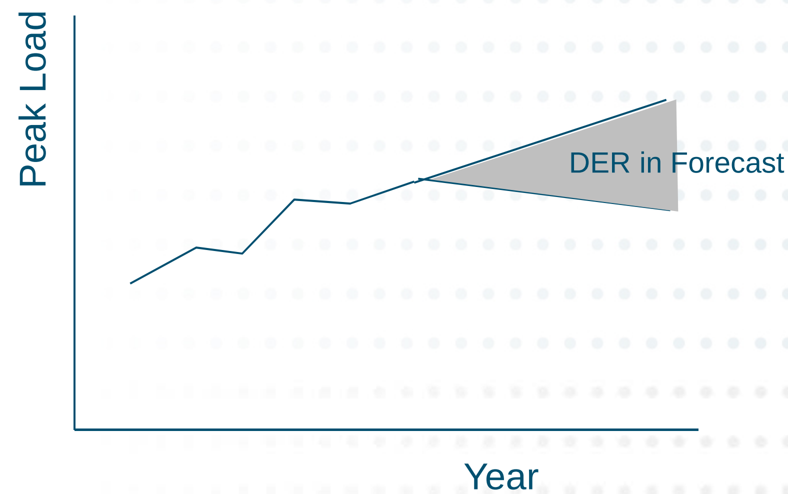
Developing the Counterfactual

- **Use system average marginal costs from years prior to intensive DER installations, and add DDOR hot spots.**
  - Easy, but relies on old information
- **Use counterfactual load growth estimates and identify rough estimates of needs with unit costs**
  - Could require extensive resource commitment by IOUs
- **Use difference between GNA and DDOR projects as a proxy for additional projects that would be required under the counterfactual**
  - Assumes that GNA needs that are easily addressed by low cost solutions now, would have required more expensive upgrades in the counterfactual world.

Developing the Counterfactual

+ **Use GRC data on historical load growth related investment and system growth to estimate the value of deferral embedded in forecast future DER**





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DRP Track 1

PG&E Proposal for DPA Level Distribution Avoided Cost for Input into DERAC

Prepared for CPUC Workshop - Discussion Purposes Only

Together, Building a Better California

Background

- PG&E Proposal submitted on December 5, 2017 responding to Ordering Paragraph 15 of D. 17-09-026.
- Decision 17-09-026, OP 15 states: “ … the Investor-owned Utilities (IOUs) are ordered to file and serve proposals for modeling and/or methodological approaches that enable Locational Net Benefit Analysis to calculate Distribution Planning Area-level avoided Transmission & Distribution values for input into the Distributed Energy Resources Avoided Cost Calculator.”
- The Distributed Energy Resources Avoided Cost Calculator (DERAC) model is a commission-adopted, public model developed by Energy & Environmental Economics that produces indicative projections of hourly avoided costs that are used as inputs into IOU program cost effectiveness models.

Agenda

- Use case for PG&E proposal – What are we trying to accomplish?

- What is in the current DERAC model for PG&E distribution avoided costs?

- Overview of PG&E's proposal:
  - Linking to Distribution Deferral Opportunities Report (DDOR)
  - Bifurcation into Base and DPA Specific avoided costs
  - The 4 "R"s – avoided costs in the context cost-effectiveness analysis.

- Discussion

Use Case - What is the Proposal Trying to Accomplish?

The Use Case is to support the design and evaluation of targeted customer programs:

- In the Energy Efficiency 2015 and Beyond Rolling Portfolios proceeding (R.13-11-005), IOUs were directed to "work with Commission Staff to determine how much of a departure from default PV[Gen] and PV[TD] values in cost calculators is appropriate to capture the locational value for such [targeted] projects."
- In the Demand Response OIR 2013 (R.13-09-011), the Commission observed that: "part of the value of a DR program is its ability to avoid [T&D] investment and upgrades to California's electricity system. These avoided T&D costs are an input to DR cost-effectiveness (C-E) analysis. The DR C-E Protocols allow the value of these avoided T&D costs to be adjusted to reflect the extent to which a DR program actually avoids T&D costs."

PG&E's proposal is designed to address Commission's directives in DRP Track 1 and in prior EE and DR proceedings to develop locational T&D avoided cost metrics that can support the design and evaluation of targeted customer programs.

Current DERAC Distribution Avoided Cost Calculation

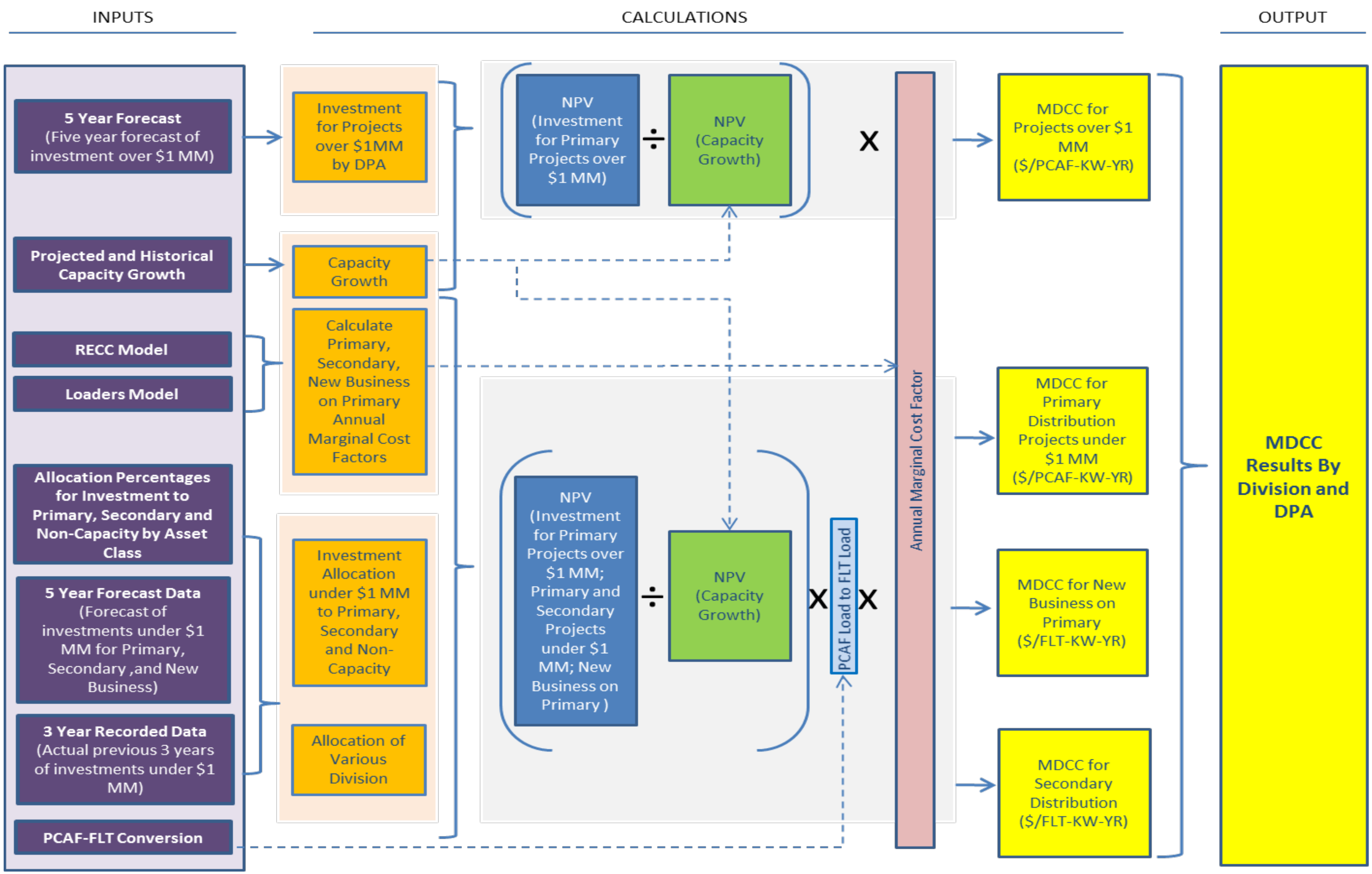
Current distribution avoided cost in DERAC includes costs of both deferrable and non-deferral projects.

Current distribution avoided cost in DERAC are aggregated up to the climate zone level providing little actionable information to support the design and evaluation of locationally targeted programs for the purpose of deferring distribution infrastructure spending.

Current distribution avoided costs in DERAC are updated every three years based on PG&E's GRC Phase II load growth related distribution marginal cost calculations.

Current Load Growth Related Distribution Marginal Cost Model

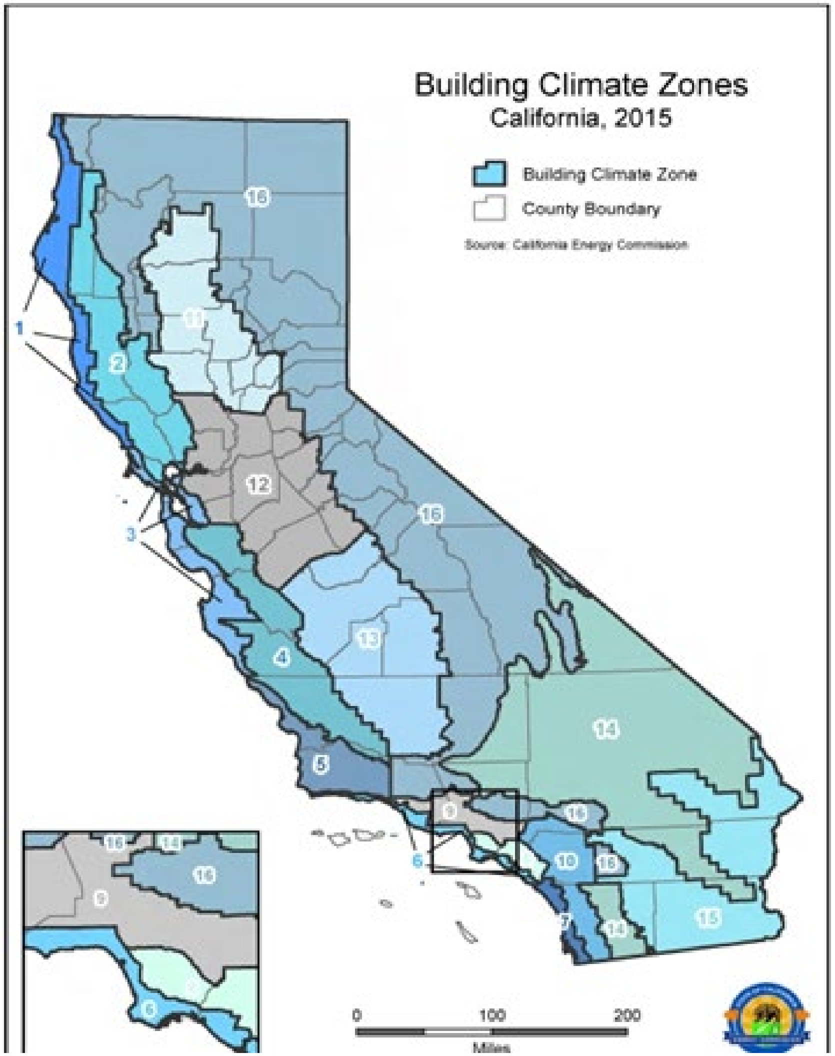
Flow Chart For Current Distribution Marginal Cost/Avoided Cost Model



Current Distribution Avoided Costs in DERAC

Distribution Avoided Costs in Current DERAC Model	
Climate Zone	($/PCAF-kW-yr)
1	$49.94
2	$22.55
3A	$43.90
3B	$23.55
4	$76.90
5	$46.70
11	$39.16
12	$52.66
13	$39.70
16	$44.95

California Building Climate Zone Areas



PG&E's Proposed Enhancements to Distribution Avoided Cost Calculation

Bifurcate the distribution avoided costs into two components:

Base component includes forecast cost of all projects under $1 million consistent with the current distribution avoided cost methodology;

DPA Specific component includes only costs of deferrable projects per most recent available DDOR.

Base component of distribution avoided costs can be used for design and evaluation of non-targeted customer program.

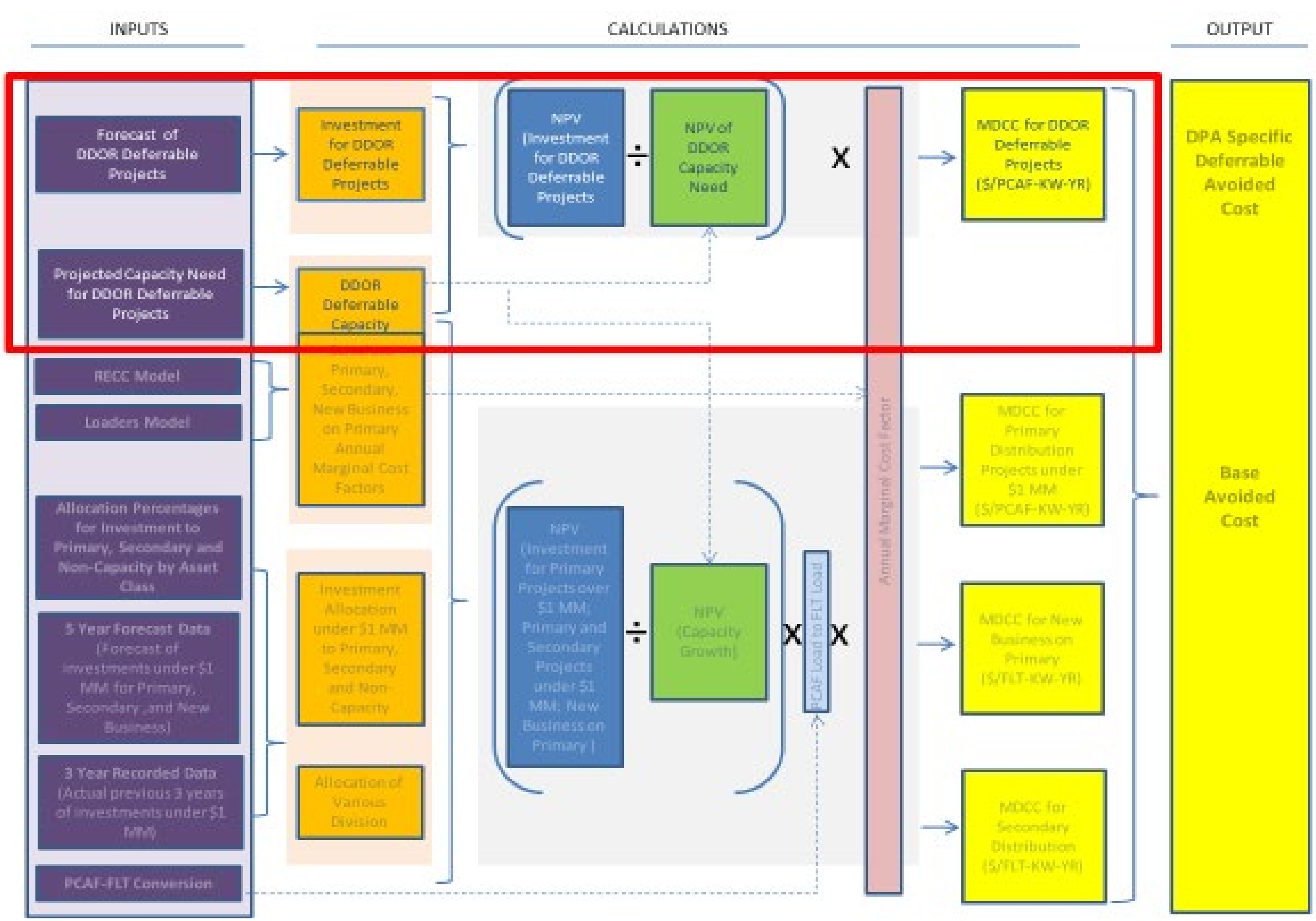
DPA Specific component of distribution avoided costs can used for design and evaluation of targeted programs.

Base component of distribution avoided costs updated based on GRC filing consistent with current methodology.

DPA Specific component of distribution avoided costs updated annually consistent with most recent available DDOR.

Proposed Model for Bifurcated Distribution Avoided Costs

Flow Chart For Proposed Enhancements to Distribution Avoided Cost Model



Bifurcation of Avoided Cost into Base and DPA Specific Components

Hypothetical Example of Bifurcated Distribution Avoided Costs

Division	Planning Area	DPA Specific $/PCAF-kW-year	Base $/PCAF-KW-year
Division A	DPA 1		25.00
Division A	DPA 2		25.00
Division A	DPA 3		25.00
Division A	DPA 4		25.00
Division A	DPA 5	200.00	25.00

Overview of Proposal – Apply the "4Rs" Criteria for Targeted Programs

Develop "4Rs" Criteria for DER Programs to Capture the DPA Specific Component

"4Rs" concept is currently adopted for Demand Response programs

- **Right Time**: DER program can be deployed in time to defer some or all of the costs of planned or needed distribution system upgrades (i.e., before local conditions become severe enough to require upgrades).

- **Right Place**: DER programs both 1) exist in areas where additional distribution capacity is needed (i.e. are located in areas where load growth would result in a need for additional delivery infrastructure but for the DER program) and 2) can also be relied upon for local T&D equipment loading relief (e.g., can be dispatched just in the local area, not only system-wide.

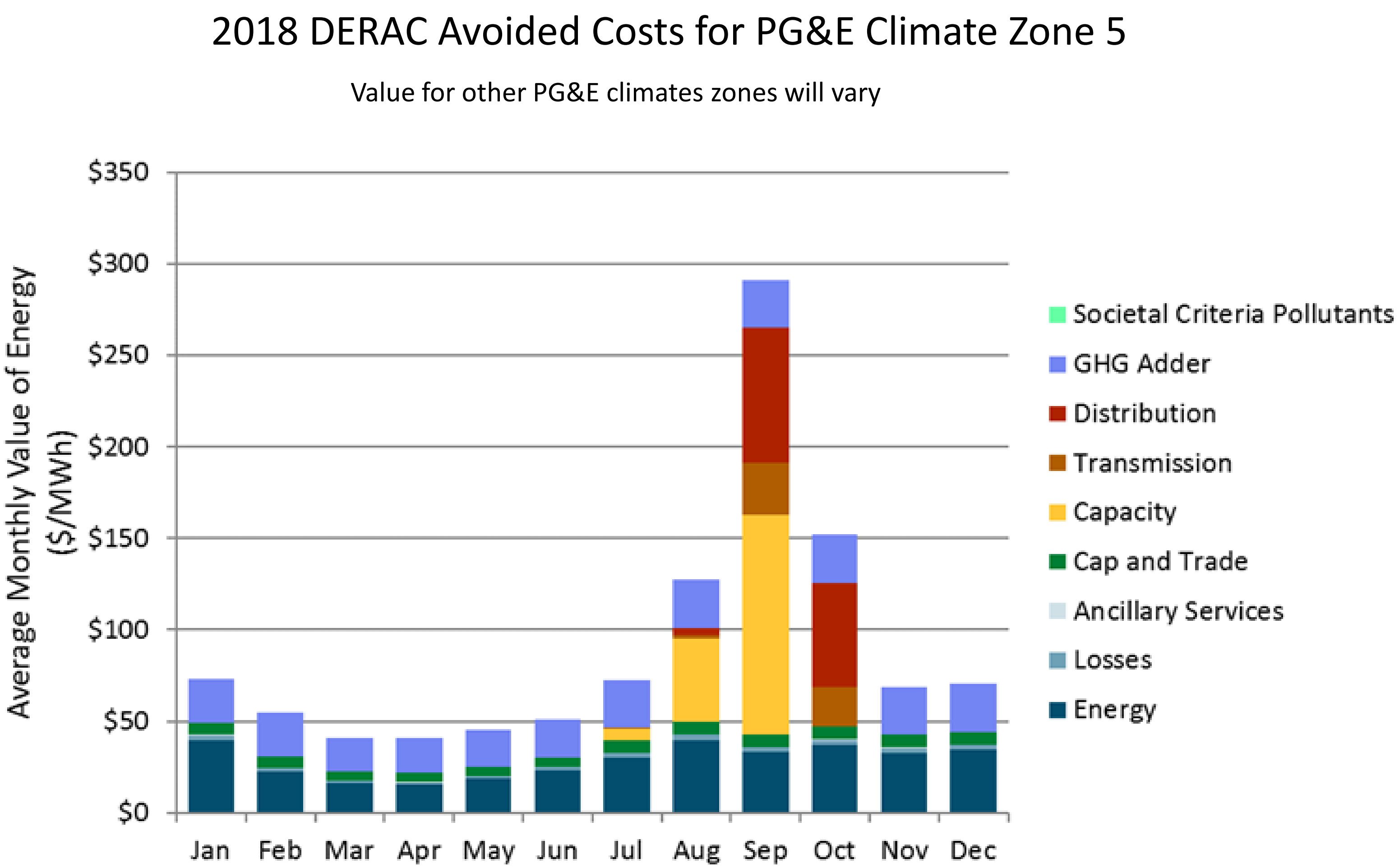
- **Right Certainty**: There is sufficient certainty that the DER program, either as a stand-alone resource or in combination with other resources, can provide the demand reductions in sufficient quantity and longevity to defer upgrade costs. For example, there must be a sufficient number of customers and the appropriate types of DERs to provide a reasonable level of certainty that needed demand reductions can be provided.

- **Right Availability**: DER program will be available when needed. This is a similar calculation as for the Demand Response cost-effectiveness A-factor, although specific to the local area need that is driving the infrastructure project. It should take into account that for DERs to be able to avoid sub-transmission and distribution investment, the DERs must be available to reduce load consistent with the need in the local area.

Appendix Slides

- Graph of Current DERAC Avoided Costs for Climate Zone 5
- Explanation of PG&E's PCAF Calculation
- Heat Map of Division PCAFs
- Relationship Between Marginal Cost and Avoided Cost

Avoided Costs in Current DERAC Model

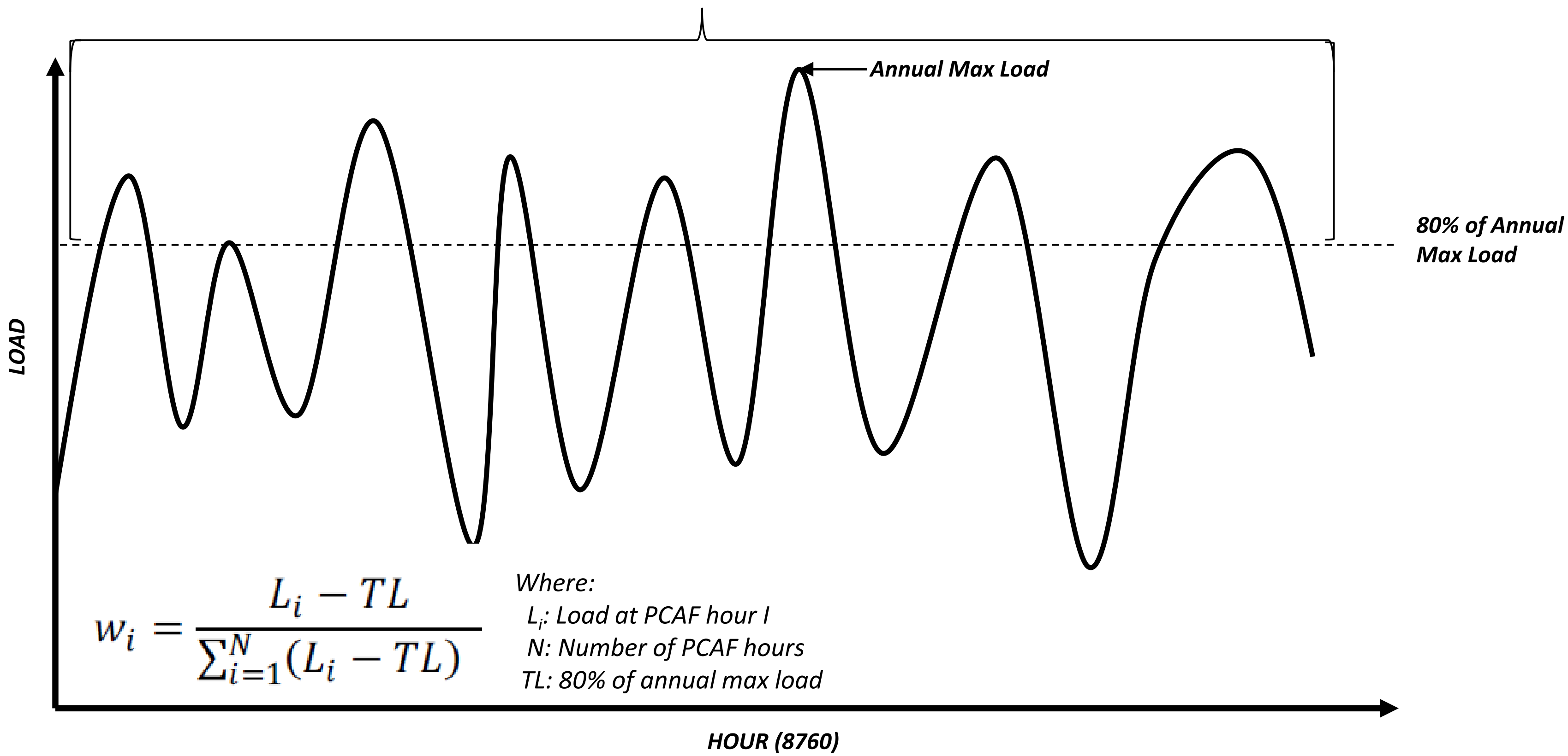


Proposed Peak Capacity Allocation Factor (PCAF) Methodology

PCAF Methodology Overview

- PCAF kW is a weighted measure of the top 20% of 8760 load. Hours with the highest peaks carry the most weight
- PCAFs are used to determine what hours/TOU periods are the drivers of marginal distribution costs.

Weighted PCAF kW



$$w_i = \frac{L_i - TL}{\sum_{i=1}^{N}(L_i - TL)}$$

Where:
L_i: Load at PCAF hour I
N: Number of PCAF hours
TL: 80% of annual max load

Distribution of PCAFs by Hour – Summer (Jun-Sep)

TABLE 12-5
SUMMER (JUNE-SEPTEMBER) PCAF DISTRIBUTION FOR PG&E'S 19 DIVISIONS

Hour Ending at Summer	CENTRAL_COAST	DE_ANZA	DIABLO	EAST_BAY	FRESNO	HUMBOLDT	KERN	LOS_PADRES	MISSION	NORTH_BAY	NORTH_VALLEY	PENINSULA	SACRAMENTO	SAN_FRANCISCO	SAN_JOSE	SIERRA	SONOMA	STOCKTON	YOSEMITE	Weighted All
1:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
7:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
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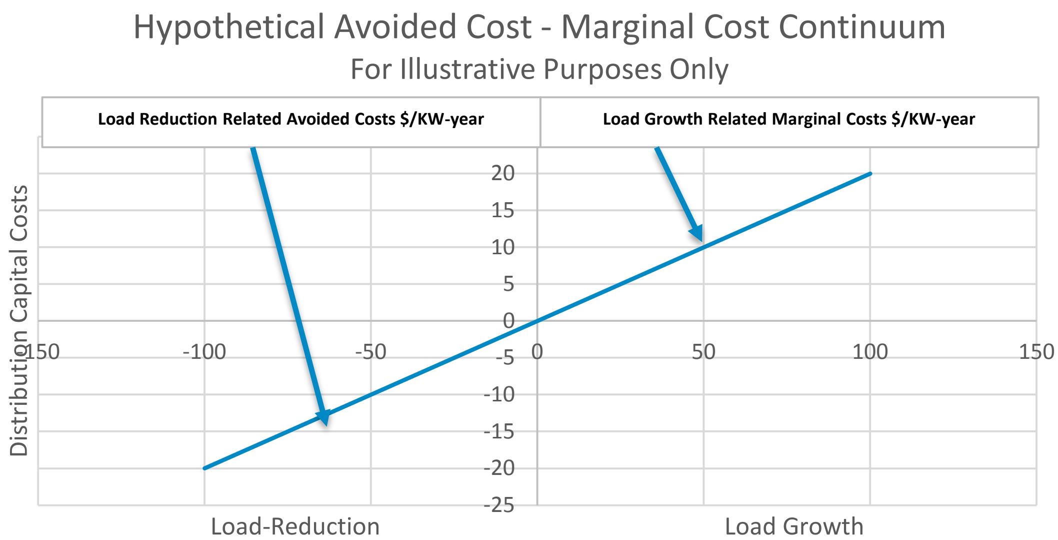
12:00:00 AM	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Logical Relationship Between Marginal Costs and Avoided Costs



Hypothetical for Illustrative Purposes Only			
Load Growth	$/KW-year	=	$Capital Costs
-20	5		-100
-15	5		-75
-10	5		-50
-5	5		-25
0	5		0
5	5		25
10	5		50
15	5		75
20	5		100

- Both the current DERAC avoided costs and PG&E's proposed DPA level avoided costs assume a linear relationship between distribution capital costs per KW-year incurred due to load growth and distribution capital costs per KW-year avoided due to load reduction.

- For a "counterfactual" analysis to have value it would need to show that this assumption of linearity between incurred and avoided capital cost is not correct and either:
  - Capital costs per KW-year avoided due to load reductions are higher than capital costs per KW-year incurred due to load growth.

    or
  - Capital costs per KW-year avoided due to load reductions are lower than capital costs per KW-year incurred due to load growth.

Conceptual Approach to Calculating Locational Avoided Cost of Distribution

Avoided Cost of Transmission and Distribution Workshop
Energy Division
December 20, 2018

PURPOSE OF A "CONCEPTUAL" APPROACH

- Simplified method to estimate "unspecified" avoided Dx costs from a "counterfactual DER forecast" using data from:
    - General Rate Case (GRC),
    - Grid Needs Assessment (GNA)
    - Distribution Deferral Opportunities Report (DDOR)
- Meant to facilitate a conversation on the challenges associated with calculating an avoided Dx capacity value.
- Main challenge is dealing with inherent uncertainty in the DER forecast.
    - Discrepancies between actual load and what was forecasted - both load levels and location.
        - This can misalign value (e.g. resource procurement) with grid needs.
- This uncertainty – if embedded in a resource procurement mechanism - may represent an unacceptable level of financial risk for non-participating customers.

Term Definitions

- A 'counterfactual DER forecast' is a load forecast that effectively adds back in the amount of DERs that are embedded in the load forecast used to identify "specified" deferrals in the DDOR.
- 'Specified' deferrals refer to specific Dx upgrade projects that are targeted for deferral by solicited DER solutions.
- 'Unspecified' deferrals are Dx capacity upgrades that never materialized due to 'autonomous' DERs

APPROACH CAN BE EXPRESSED AS A "P*Q" EQUATION

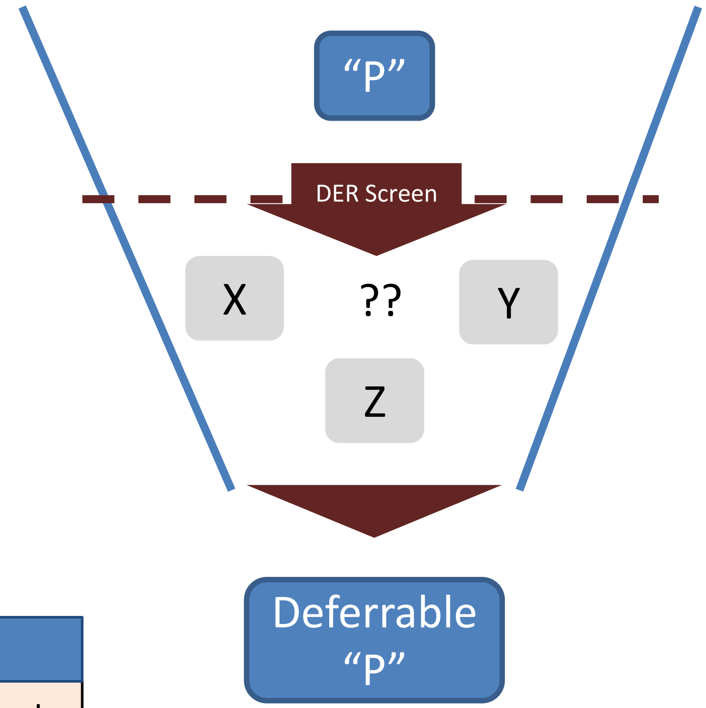
- Calculation relies on marginal cost data (from the GRC) and identified grid needs and DER solutions (from the GNA and DDOR).
  - Tying calculation to GRC, GNA and DDOR connects the methodology with latest data and streamlines the level of effort involved.
- Summation of P and Q equals notional, locational avoided Dx capacity value.

Basic Calculation Formula
Avoided Dx Capacity Costs = P * Q Where: P = Marginal Cost of Dx Capacity Q = MW of Deferrable Dx Capacity

The following slides demonstrate how "P" and "Q" can be calculated using existing data from the GNA, DDOR and GRC as well as highlight key methodological questions that will need to be addressed in this – or any – resultant calculation.

"P" VALUE IS A MARGINAL COST OF DX CAPACITY DERIVED FROM THE IOU'S GRC

- "P" variable is based on marginal Dx capacity costs from the IOUs GRC filing.
- Marginal costs are built up from several components.
- For example, PG&E's Marginal Distribution Capacity Costs (MDCC) is a composite of three subcomponents:
  - Primary Dx capacity costs.
  - Secondary Dx capacity costs for new businesses.
  - Secondary Dx costs.



Key Methodological Questions

• Does the marginal Dx capacity cost in the GRC reflect undeferrable costs that should be removed?
  • If so, what components?
• Alternatively, should the marginal Dx capacity cost value be discounted by a constant factor (e.g., 0.85) to reflect undeferrable costs?
  • What is the most reasonable estimate of that discount factor?

"Q" VALUE CALCULATION IS A STEPWISE PROCESS USING DATA FROM THE GNA & DDOR

Step 1: Calculate Circuit-Level Counterfactual Capacity Overload

Step 2: Estimate System-Level Dx Capacity that is Deferrable Based on DDOR Data

Step 3: Apply DDOR-derived, Deferrable Dx Capacity Estimate to Individual Circuits Identified in Step 1

The following slides highlight the calculation of each step using actual data categories from the GNA – although the underlying numbers are "dummy" data to facilitate discussion.

"Q" STEP 1: CALCULATE CIRCUIT-LEVEL COUNTERFACTUAL CAPACITY DEFICIENCY

- The circuit-level counterfactual forecast stems from GNA data on the capacity deficiency on each circuit to 2024.
- GNA data also contains data on forecasted DERs, by technology, that is 'assigned' to each circuit based on disaggregation methodology.
- Adding back in the forecasted DERs that are 'assigned' to each circuit can produce a notional estimate of counterfactual load.

Table 1: Hypothetical Calculation of Counterfactual Deficiency Using Dummy Data

Circuit ID #	Net load in 2024 (MW)	Deficiency in 2024	DER growth in 2024 (MW)					Counter-factual Load	Counter-factual % Deficiency	Capacity overload (MW)
			EE	DG	Storage	DR	EV			
1	8	115%	0.3	0.5	0.05	0	-0.09	8.76	129%	2.52
2	5	104%	0.2	0.2	0.05	0.002	-0.06	5.392	112%	0.67
3	6	124%	0.3	0.3	0.01	0.001	-0.04	6.571	144%	2.90
4	10	122%	0.7	0.9	0.1	0	-1	10.7	137%	3.98
5	12	105%	1	1.5	0.09	0	-1.1	13.49	118%	2.47

Projected circuit deficiency in GNA

Estimate from CEC system-wide DER forecast disaggregated to each circuit

Result is each circuit's forecasted capacity overload

Key Methodological Questions

- Should all circuits be included in the calculation or only a subset?
  - Which subset and why?
- What are the limitations of an "additive" approach versus a powerflow modeling approach?
- How can avoided costs past planning horizons of 5 years GNA and 10 years for Dx planning be accounted for?

"Q" STEP 2: ESTIMATE DX CAPACITY UPGRADES THAT ARE POTENTIALLY DEFERRABLE BY DERS

- Step 2 estimates the percentage of Dx capacity upgrades that can be deferred by DERs.
- Table 2 shows how this calculation can draw from data in both the DDOR and GNA.
  - Total system-wide capacity upgrades as identified in the GNA.
  - Fraction of the GNA total that can be deferred by DERs as identified in the DDOR (subject to an RFO process).
- This resulting percentage – 16% in this hypothetical example – is a proxy for Dx capacity upgrades that can be deferred by DERs.

Table 2: Proxy Calculation of Dx Capacity that is Deferable by DERs Using Dummy Data	
System-wide Dx Upgrade Requirements in GNA (MW)	2,500
Dx Upgrade Capacity Deferrable by DERS in DDOR (MW)	400
Percentage of System-Wide Dx Capacity Upgrades That Can Be Deferred by DERs	16%

Key Methodological Questions

- Should the percentage be based on the number of projects instead of the MW capacity?
- Does this approach adequately capture the locational aspect?
- Should the calculation be updated in coordination with the annual GNA/DDOR cycle?

“Q” STEP 3: APPLY DEFERRABLE DX CAPACITY ESTIMATE TO INDIVIDUAL CIRCUITS IDENTIFIED IN STEP 1

- Step 3 applies the result of Step 2 (i.e. 16% in this example) to the estimated capacity overload of each circuit resulting from Step 1.
- This represents the fraction of the Dx capacity identified in the GNA that notionally is deferred by DERs embedded in the forecast.

Table 3: Notional, Circuit-Level Dx Deferred Capacity

Circuit ID #	Capacity Overload (MW from Step 1)	% of Dx Capacity Upgrades Deferrable by DERs (from Step 2)	Dx Capacity Deferable by DERs (MW)
1	2.52	16%	0.40
2	0.67	16%	0.11
3	2.90	16%	0.46
4	3.98	16%	0.64
5	2.47	16%	0.40

Key Methodological Questions

- Should there be a range around the results of Step 2?

FINAL CALCULATION – LOCATIONAL AVOIDED DX CAPACITY COSTS

- Multiply the marginal Dx capacity cost (i.e. "P") by the total notional Dx capacity deferrable by DERs (i.e. "Q" as defined by Table 3)
- Divide product (i.e. P * Q) by the forecasted level of DERs expressed in MW for each circuit.
- Results in a $/kW value that needs to be applied to the Peak Capacity Allocation Factor (PCAF) method.

	IOU
Marginal Cost	

→ "P"

Table 3 Output	
Circuit ID #	Dx Capacity Deferable by DERs (MW)
1	0.40

→ "Q"

$$\left[\frac{(P * Q)}{\text{Circuit-Level DER Forecast}} \right] \Longleftrightarrow \left[\text{PCAF} \right]$$

Key Methodological Questions
• What is the best method to account for the PCAF in this calculation?

Discussion

Questions for Discussion

• Based on methods and issues discussed today, does the effort to calculate locational avoided cost for DERs embedded in the forecast pass a 'feasibility threshold' (ie. produces results that are reliable enough to be meaningful and/or applicable for other decision-making processes)?
    • How can we estimate which circuit location to which apply the locational avoided cost, when it depends on many factors that would result in the distribution deferral?
    • What is the appropriate balance between granularity / precision of the calculation and the resultant use of the calculation?
• Are all components of the marginal cost calculation deferrable by DERs?
    • If not, is ED's approach of discounting the marginal Dx capacity cost value by a constant factor (e.g., 0.85) to reflect undeferrable costs reasonable?
    • Otherwise, what is the most reasonable estimate of that discount factor?
• How can avoided costs past planning horizons of 5 years GNA and 10 years for Dx planning be accounted for?

END

SCE's Avoided Transmission Cost Proposal

Summary from SCE's December 2017 Filing

December 20, 2018

Agenda

- Background
- High Level Methodology Overview
- Regions
  - Import
  - Export/Transfer
  - Ambiguous
- Estimated Value
  - Calculation
  - Application to Regions
- Final Thoughts

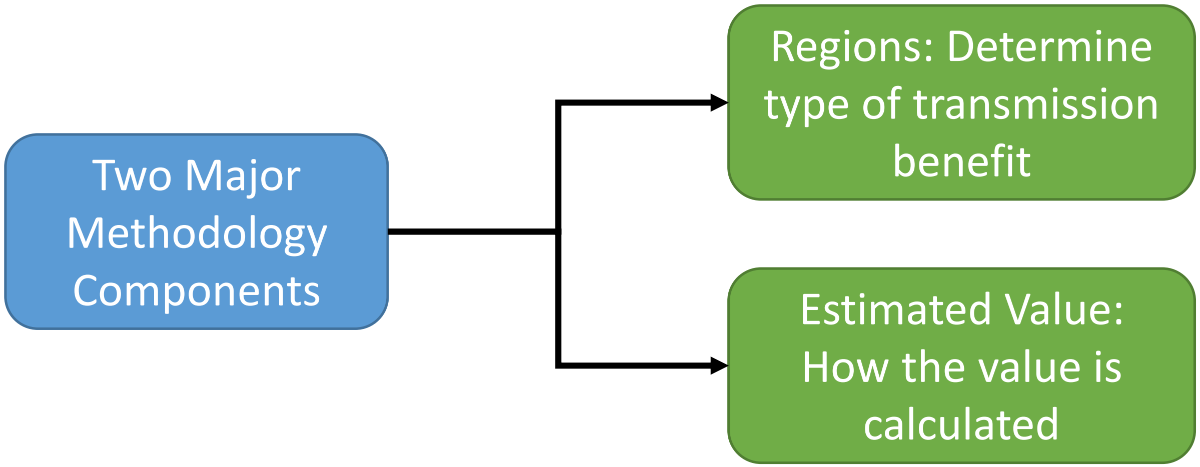
Background

- On December 5, 2017, SCE submitted its proposal to the CPUC that describes methodologies to incorporate locational transmission and distribution avoided cost values into the Distributed Energy Resource Avoided Cost Calculator (DERAC)
  - *"The Investor-owned Utilities (IOUs) are ordered to file and serve proposals for modeling and/or methodological approaches that enable Locational Net Benefits Analysis to calculate Distribution Planning Area-level avoided Transmission & Distribution values for input into the Distributed Energy Resources Avoided Cost Calculator."*[1]
- SCE's proposal consisted of a distribution methodology and a transmission methodology to address the CPUC's request

1. D. 17-09-026, Ordering paragraph #15

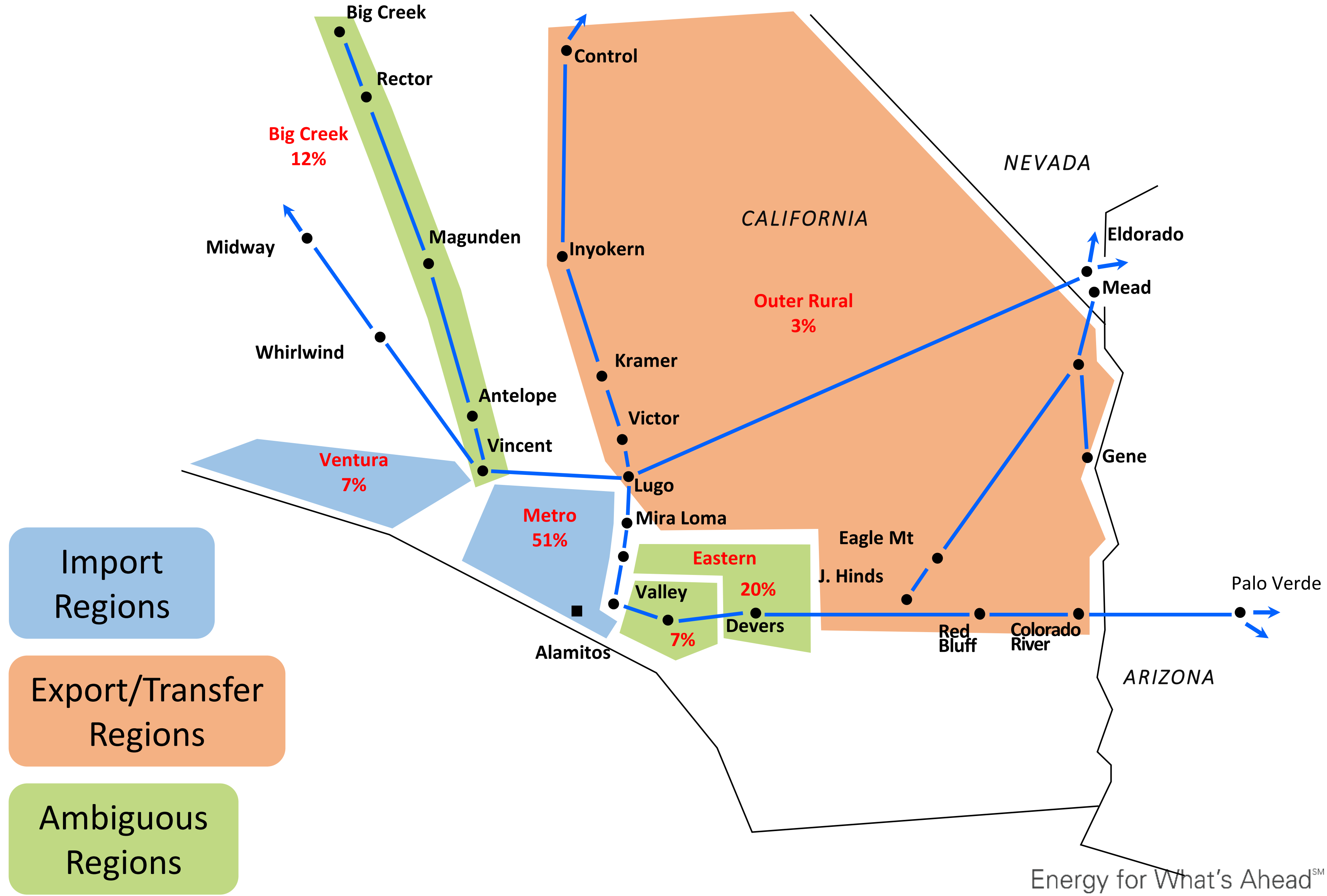
High Level Methodology Overview

- SCE's proposal is a simplified approach
  - Fits SCE's transmission topology
  - Provides an estimation of value in different locations



- SCE's proposal is a starting point for discussion

SCE's Transmission System Divided into Three Regions



Energy for What's Ahead℠

Summary of Regions

Category	Regions	Load and Generation Characteristics	Effect of Net Peak Load Reduction	Value of Net Peak Load Reduction
Import	Metro	Major load center with limited generation	Reduce transmission constraints through reduced imports	Positive Value
Import	Ventura	Isolated load center with limited generation		
Export/Transfer	Outer Rural	Limited load and extensive renewable energy development	Exacerbate transmission constraints through increased exports	Negative Value
Ambiguous	Big Creek	Load and generation both extremely weather dependent	Highly varied from year to year	Neutral
Ambiguous	Valley	Limited growth, moderate renewables development	Uncertain	
Ambiguous	Eastern			

Steps to Estimated Value

- Identify DER deferrable transmission projects
  - Likely need to collaborate with CAISO
- Determine cost of transmission projects
- Calculate transmission value
  - Leverage the same methodology, a regression analysis, as in SCE's GRC Phase 2 proceeding for distribution marginal cost

Applying Estimated Value to Regions

Category	Regions Included	Value
Positive Value	Metro, Ventura	Positive estimated transmission value based on escalating fraction approach: • Years 1-10: Zero • Years 11-20: Straight line escalation from 10% to 100% (10% increase each year) • Years 21-30: 100%
Negative Value	Outer Rural	Negative estimated transmission value; same schedule as above
Neutral	Big Creek, Valley, Eastern	Zero in all years

Final Thoughts

- Any implementation of a transmission avoided cost methodology will need careful consideration of:
    - Appropriate application to a specific use case
    - Association of avoided costs with real life benefits
    - The need to avoid double counting of benefits
        - Generation capacity and transmission
- LNBA has focused on the benefits of DERs
    - However, any consideration of DERs should account for the costs of the DERs

SEIA Perspective on Marginal/Avoided CAISO Transmission Costs

Tom Beach, Crossborder Energy

December 20, 2018

A Foundational Benefit of DERs

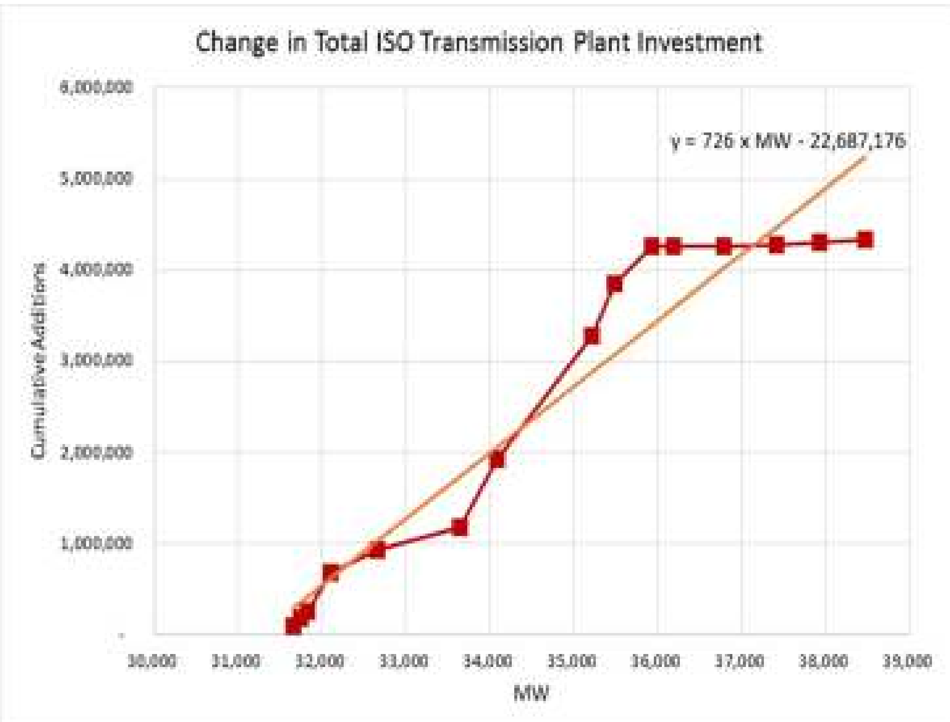
- An essential attribute of distributed energy resources is their location.
  - BTM or IFM on the distribution system near end use loads
  - Potential to be a wires alternative
  - “Wires” include CAISO transmission as well as IOU distribution.
- DERs can avoid bulk transmission
  - Serve end use loads, reduce peak demand on the grid
  - Reduce peak loads that contribute to reliability issues & congestion
  - Increase the market penetration of renewables
- Zero is not the best estimate for avoided CAISO transmission
  - CAISO 2017 TPP: $2.6 billion in cancelled or delayed projects due to DERs – energy efficiency and rooftop solar

Calculating Marginal CAISO Transmission Costs

- CA is relying on DERs to serve load growth & reduce GHGs.
- Transmission projects have multiple functions.
- DERs have capacity, reliability, economic, and policy benefits.
- All "types" of transmission costs are potentially deferrable.
  - Load growth – serving peak demand
  - Reliability – contingencies in high load hours
  - Economic – congestion can be impacted by demand level
  - Policy-driven – RPS based on MWh goals
- Start with locational avoided CAISO transmission costs by IOU
  - Use a long-run marginal cost calculation.
  - DERs also can be part of "non-wires" solutions to specific constraints.

Example 1: SCE avoided CAISO transmission

- NERA regression of all SCE CAISO-level transmission investments versus peak capacity



Steps	Cost
1. Regression – All FERC T vs. nameplate AA-Bank capacity	726 $ per kW
2. *plus* General Plant Loader @ 7.3%	53 $ per kW
3. Subtotal	779 $ per kW
4. *times* RECC @ 9.94%	77 $/kW-year
5. *plus* O&M Costs from FERC Form 1	7 $/kW-year
6. Avoided CAISO Transmission	84 $/kW-year

Example 2: SCE avoided CAISO transmission

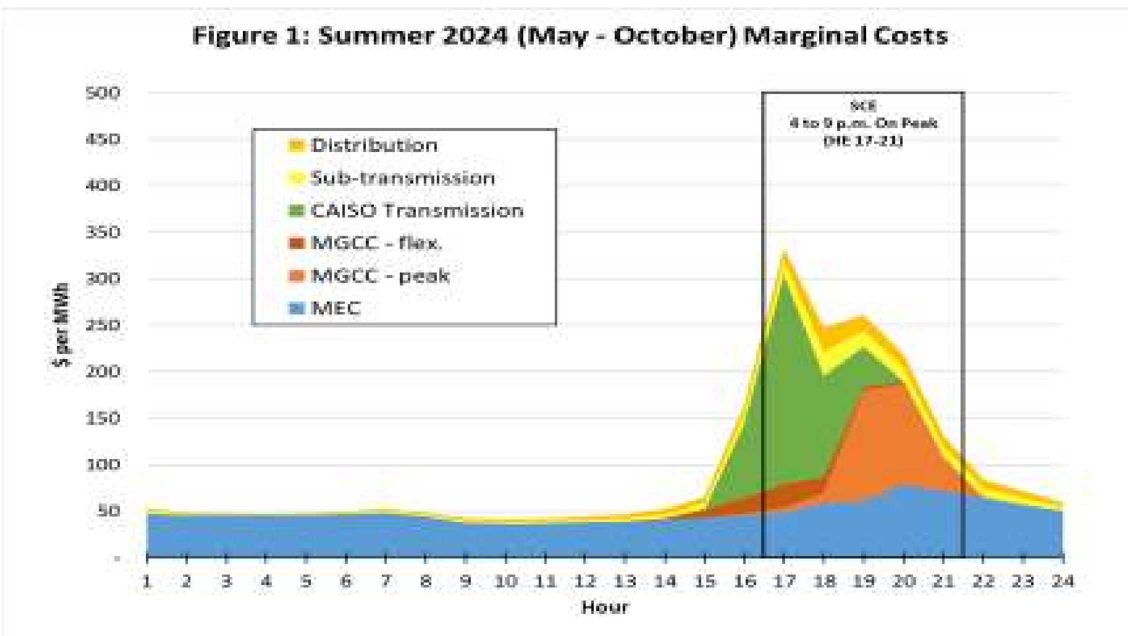
- Two-part avoided CAISO transmission costs
  1. $ per kW-year for peak-related transmission
     - Same calculation as (1), without RPS transmission investments
     - Result: $21 per kW-year avoided CAISO transmission cost

  2. $ per MWh value for "policy-driven" RPS transmission

Steps	Cost
1. RPS-related T Investment Costs	256 $ per MWh
2. *plus* General Plant Loader @ 7.3%	19 $ per MWh
3. Subtotal	275 $ per MWh
4. *times* RECC @ 9.94%	27 $ per MWh
5. *plus* O&M Costs from FERC Form 1	4 $ per MWh
6. Avoided CAISO Transmission	31 $ per MWh

Allocating avoided CAISO transmission costs to hours

- Use peak capacity allocation factors (PCAFs)
  - For T: hourly profile of gross loads above a threshold of 90% of the system peak load
  - Weighted by how much an hourly load exceeds the 90% threshold
- Example of use of SCE system-level PCAFs



Principles and Approaches to Estimating Locational Avoided Cost of Transmission

Avoided Cost of Transmission and Distribution Workshop
Energy Division
December 20, 2018

Procedural Background on Calculating Avoided Cost of Tx

- Track 1 decision determined that avoided Tx value needed to be adopted to include in the Avoided Cost Calculator update
  - Avoided cost calculator currently does not include a FERC jurisdiction, high voltage Tx value
- Locational Net Benefit Analysis (LNBA) Working Group vetted issues in avoided Tx as part of the Long Term Refinements of the LNBA
- 6 parties developed proposals for calculating the avoided cost of Tx in LNBA WG Final Report, submitted on January 9, 2018
  - SEIA, TURN, Cal PA, Clean Coalition, SCE, PG&E and SDG&E; comments from CAISO

Goals of the Avoided Cost Calculator Update

- **First priority:** Create a non-zero value for high voltage avoided Tx capacity
  - 7-10 GW of DERs capacity has been built into the grid
  - CAISO's 2017-18 Tx Plan cancelled/modified previously approved projects avoiding $2.6 B in costs that may be in part due to DERs
  - Although there's evidence that DER growth defers Tx capacity needs, accurately accounting for quantity is challenging
  - A system-wide estimate is more accurate than a zero value
- **Second priority:** If locationally-differentiated values can be calculated, then include them in avoided cost calculator
  - Determine how existing CAISO data might be used to inform a locational value based on Local Capacity Requirement (LCR) zones
  - Alternatively, consider SCE's proposal of defining import, export and ambiguous zones
  - Determine whether a locational value is substantial and reliable enough to use in some form of compensation to DERs

Overview of Tx Proposals in the Long Term Refinement WG Report

- 6 parties offered recommendations but only SCE proposed a complete methodological approach to calculating locational avoided costs of Tx
- Basic methodological options are similar for Tx as Dx:
    1. Either CAISO conducts an counterfactual Tx planning analysis to determine costs of Tx capacity needed in absence of DERs, or
    2. Use the marginal cost of Tx capacity allocated by the PCAF
- Either way, most parties stated that more analysis from CAISO was necessary to determine locational differentiation
- CAISO stated that a counterfactual planning analysis is infeasible
- Nonetheless, parties concluded more information from CAISO was needed

Potential Use Cases for Avoided Tx is similar as Avoided Dx

Tx Avoided Costs may be split in to similar categories, but we need to determine whether both of these categories would be included in the avoided cost calculator or through separate applications

Specified Deferrals

Use Cases:

- Identify DER procurement opportunities to meet Local Capacity Requirement (LCR) needs
- Design tariffs to target location capacity requirements
- Must determine whether to include in the avoided cost calculator

Avoided Cost Calculation:

- Should assign a value to DERs that can relieve Tx congestion in LCR Areas
- Designed for targeted procurements

Unspecified Deferrals Avoided Cost Calculator

Use Cases:

- Analysis used to inform long-term DER-related programs and policies
- Potentially include locational value in NEM, EE, DR payments
- Provide inputs for IRP RESOLVE model

Avoided Cost Calculation:

- Reflects the deferred Tx costs that result from DER growth that embedded in the forecast due to existing programs and tariffs

Key Components of a Locationally Disaggregated Avoided Cost of Tx

Calculating the avoided cost of Tx includes the following components, however the parties proposals differed in the sequencing of these steps:

- Identify a subset of Tx costs that can deferred by load growth reduction
- Define locational zones of Tx and proportion of costs that are applied at system or locationally specific level
- Calculate the annualized, levelized cost by dividing the total cost from deferrable Tx capacity, or based on marginal cost of Tx
- Calculate the coincidence of deferral needs to DERs embedded in the forecast based on DER and load shape based on the peak capacity allocation factor (PCAF)

The following slides consider how these steps could be calculated

Identify Tx Costs Deferrable by DERS

Energy Division straw proposal for treatment of categories of TPP costs

Source of Tx Revenue Requirements	Recommend to Include in Tx Avoided Cost	Rationale
TPP Reliability Case	Include	Changes in Tx bulk or local reliability is driven by demand growth
TPP Economic Case	Include	Driven by demand
TPP Policy Case, RPS	Exclude	New Tx to meet RPS is deferrable, but is already included in ACC GHG adder
Special Studies	Include	Case by case basis
Self Approved Transmission	Exclude	Driven by load replacement

Key Methodological Questions

- Does the Local RA and/or CAISO's LCR analysis reflect discreet localized deferrable value, and if so, how should it be applied?

Define Tx zones and proportion of costs that are applied at system or locational level

Options presented in Working Group Report:

- Local RA/LCR areas
- Divide territory into import/export and ambiguous regions
  - Import regions have positive avoided costs, since they have limited local generation
  - Export/transfer regions have negative avoided costs since they produce more generation than is used
- Territory-level: Define the locational segments of Tx by NP15 and NP16

Key Methodological Questions

- ➢ Which of these options lend themselves to reliable data to inform DER compensation?
- ➢ If this is impractical, would a system-level be more useful?

How to Apply the Marginal Cost of Tx

Calculate the annualized, levelized cost by dividing the total cost by deferrable costs, or based on marginal cost of Tx

- SCE proposes “escalating fraction” approach of MTC:
  - The value begins at zero in early years and increases as an increasing percentage of MTC to 100% MTC in year 20 and all years beyond.
  - The derivation of marginal costs will incorporate use of the Real Economic Carrying Cost (RECC) methodology, which calculates the present value of the one-year deferral of capacity related capital investments.
- PG&E proposes a marginal cost based on deferrable Tx:
  - Identify a subset of planned Tx investments from the latest CAISO TPP that can be deferred by load growth reduction
  - Calculate an annualized, levelized cost by dividing the total cost from projects identified from step 1 above by the projected load growth for the Economic DER case

Discussion

Questions For Discussion

• Based on methods and issues discussed today, does the effort to calculate locational avoided cost for DERs embedded in the forecast pass a 'feasibility threshold' (ie. produces results that are reliable enough to be meaningful and/or applicable for other decision-making processes)?
    • What is the appropriate balance between granularity / precision of the calculation and the resultant use of the calculation?
    • Does these approaches adequately capture the locational aspect?
• Are all components of the marginal cost calculation deferrable by DERs?
    • If not, how should marginal Tx capacity cost value be discounted to reflect undeferrable costs?
    • What is the most reasonable estimate of that discount factor?
• What is the appropriate planning horizon for this calculation?

END

(END OF APPENDIX B)